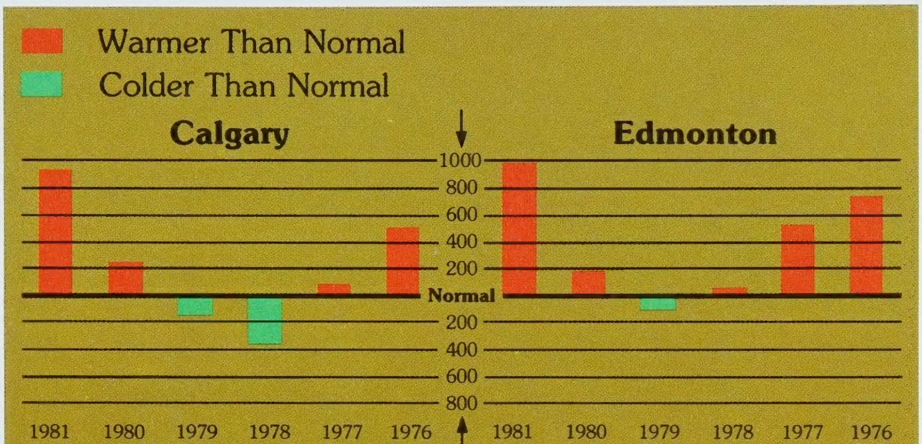
Canadian Utilities Limited Annual Report 1981

Weather Chart



Normal — 5,269 Degree Days				Normal — 5,581 Degree Days			
Year	Degree Days	Colder or Warmer ( ) Than Normal		Year	Degree Days	Colder or Warmer( ) Than Normal	
		Number	Per Cent			Number	Per Cent
1981	4,365	(904)	(17.2)	1981	4,595	(986)	(17.7)
1980	5,082	(208)	(3.9)	1980	5,396	(185)	(3.3)
1979	5,366	142	2.7	1979	5,636	120	2.2
1978	5,592	358	6.8	1978	5,530	10	(0.2)
1977	5,289	(63)	(1.2)	1977	5,124	(465)	(8.5)
1976	4,885	(494)	(9.2)	1976	4,891	(709)	(12.7)

Metric Conversion

This annual report contains operating statistics which are reported in metric units of measurement. The following information is provided to assist readers who wish to convert to imperial units.

The metric unit for measurement of energy is the joule (J) and its multiples. Large amounts of energy will be reported in gigajoules (GJ), billions of joules; in terajoules (TJ), trillions of joules; and in petajoules (PJ), quadrillions of joules.

Conversion Table

Imperial	Metric Equivalent
1 British Thermal Unit	1 054.615 joules
1 cubic foot (natural gas)	0.028 317 cubic metres (m^3)
1 barrel (petroleum liquids)	0.159 cubic metres (m^3)
1 inch	25.40 millimetres (mm)
1 foot	0.304 8 metres (m)
1 yard	0.914 4 metres (m)
1 mile	1.609 3 kilometres (km)

Contents

Highlights

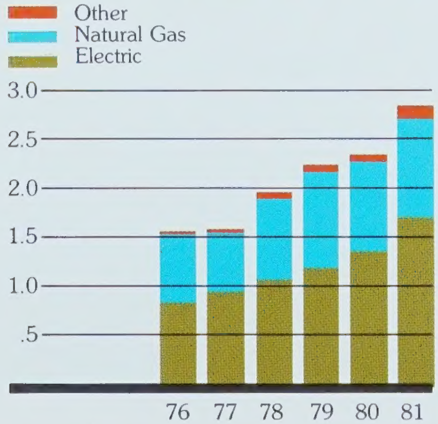
CANADIAN UTILITIES LIMITED

	1981	1980	Increase
Revenues (thousands)			
Natural gas	**$ 779,169**	$581,677	$197,492
Electric	**201,678**	149,847	51,831
Other	**43,717**	26,172	17,545
Total	**$1,024,564**	$757,696	$266,868
Net earnings attributable to common shares (thousands)	**$ 60,096**	$ 49,273	$ 10,823
Earnings per common share (per share)	**$ 2.87**	$ 2.37	$ .50
Common shareholders' equity per share (at year-end fully diluted)	**$ 17.18**	$ 15.21	$ 1.97
Dividends paid per share			
Annual	**$ 1.25½**	$ 1.14½	$ .11
Fourth quarter	**$ .34**	$ .30½	$ .03½
Average common shares outstanding	**20,911,186**	20,817,623	93,563
Capital expenditures (thousands)	**$ 235,145**	$266,984	$ (31,839)
Customers at year-end			
Natural gas	**549,773**	519,997	29,776
Electric	**134,602**	128,820	5,782

Segmented Information

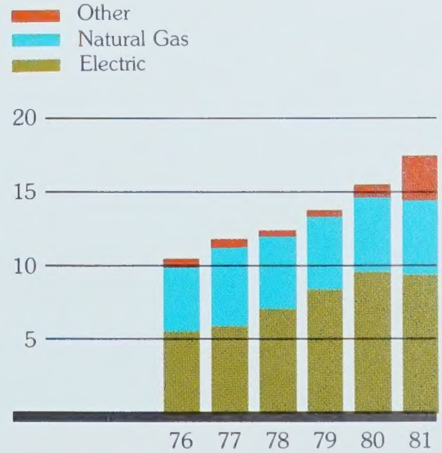
Earnings Per Common Share

(in dollars)
before extraordinary items

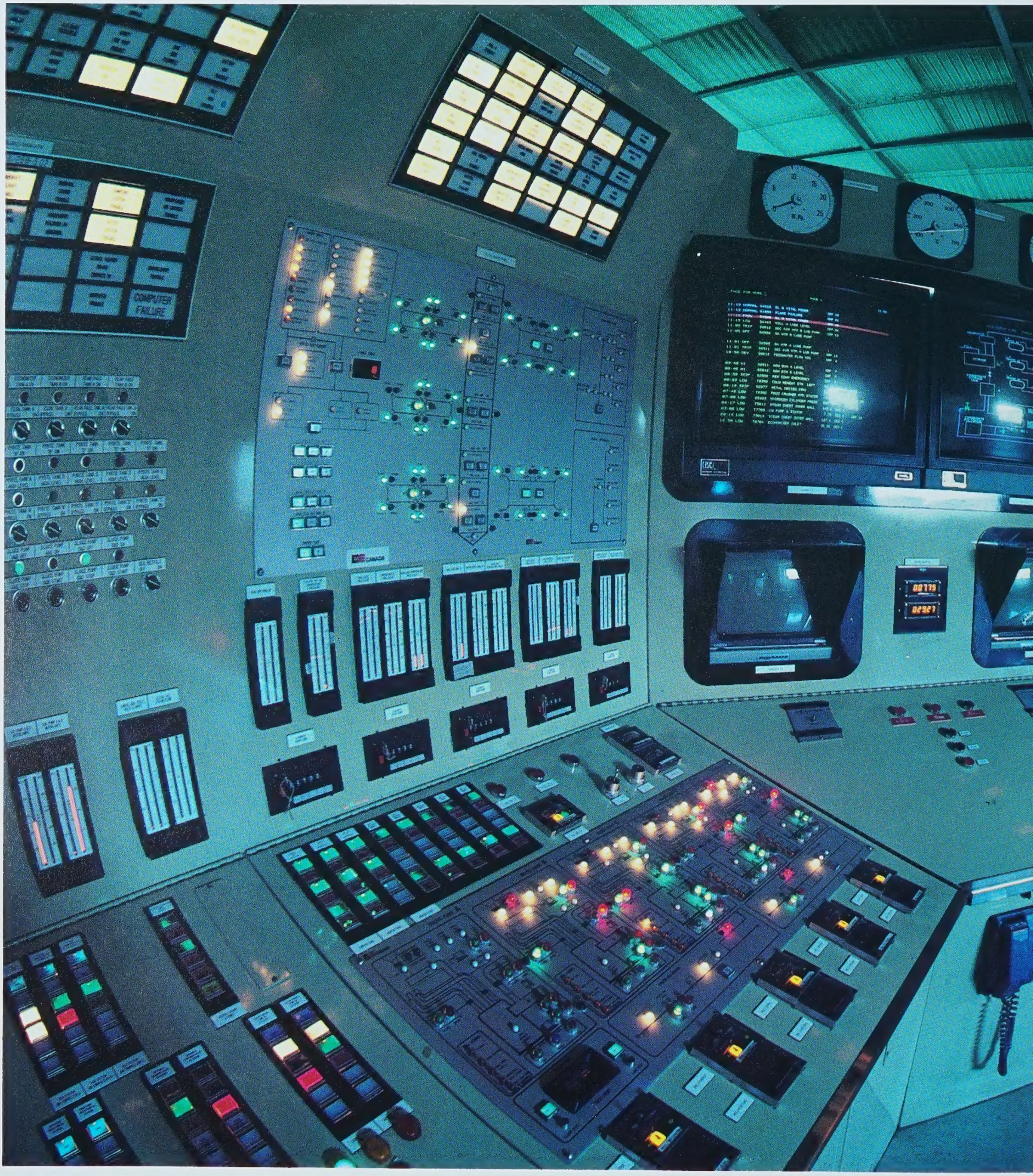


Equity Per Common Share

(in dollars)



Capital expenditures during 1981 exceeded $200 million for the second consecutive year. A major capital project completed in 1981 was the $255 million Unit #5 at the Battle River Generating Station. The unit is monitored and controlled from this instrument panel.



To the Shareholders

The year under review was marked by major accomplishments for the Company, including records in earnings and numbers of customers served — despite a retardation in the growth of economic activity in Alberta.

Improved earnings resulted largely from continued expansion of capital assets and the utility rate base as the Company increased investment to accommodate the natural gas and electric utility needs of the growing Alberta market. Net earnings were $81,437,000 compared to $61,613,000 a year earlier. After dividends to preferred shareholders, earnings attributable to common shareholders were $60,096,000 ($2.87 a common share) compared to $49,273,000 ($2.37 a share) in 1980.

Electric sales to retail customers were up 7.4% to 3,216 million kilowatt hours. Wholesale electric sales were 495.2 million kilowatt hours, a significant item for the first time, mainly because of the commencement during 1981 of the sale of half the output of the new Battle River 5 generating unit to the City of Edmonton.

Natural gas sales, because of warmer than normal temperatures and lower sales to industrial customers, declined 5% to 372.4 petajoules. Discounting the effects of unusual weather, usage of natural gas per household continues to decline with the widening implementation of energy conservation practices. Altogether 35,558 new customers were added to the

Canadian Western Natural Gas and Northwestern Utilities continued their search for additional natural gas reserves during 1981, participating in the drilling of 115 wells of which 83 were successful or are still being evaluated.

Company's gas and electric systems during the year, bringing the total to 684,375, an increase of 5.5%.

Capital expenditures in 1981 were $235.1 million, the second consecutive year such spending exceeded $200 million. The Company raised $210 million through two issues of preferred shares, an issue of debentures and a private placement of a floating rate note.

A matter of great concern during the year was the continuing disruption and lack of permanence of long-term capital markets caused by high interest rates and uncertainty concerning the future of interest rates. While economic forecasts vary, the Company believes interest rates will remain high in Canada because of heavy demand for capital funds and continuing inflation. To raise new capital under these circumstances, investors and financial markets are requiring shorter terms on debt and short-term retraction privileges on preference shares. The Company's search for capital funds, under the best terms possible, is now extending outside of Canada. In 1981, for the first time, the Company entered the European financial market with a successful $50 million (Canadian) debenture issue providing a 15-year maturity at a 17% interest rate. Additional financings in Europe and the United States are being contemplated.

During 1981 the Company's three major utility subsidiaries, Alberta Power Limited, Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, were granted a utility rate of return on common equity of 14.75%. This return was less than requested and is not sufficient to attract the equity capital that will be required in the future. An adequate base of share capital is essential to maintain the Company's financial strength and the confidence of existing shareholders.

In December 1981, Alberta Power Limited applied for an increase in rates for 1982 requesting a utility return on common equity of 17.25%, considered to be a minimum under current circumstances. In January 1982 the Public Utilities Board granted, on an interim basis, a return of 16.5%. As stated in the Board's order, "upon full and final determination, it is conceivable that the 17.25% rate forecast by Alberta Power Limited may be considered appropriate." Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited will also be applying for increased consumer rates in 1982.

Several of the natural gas rate adjustments applied for and granted during 1981 were solely in response to increases in the Federal excise tax on natural gas, the Petroleum and Gas Revenue Tax and the Federal Canadian Ownership Tax, the latter imposed mainly to pay for the Government's purchase of Petrofina Canada.

Of the Company's total $779.2 million in natural gas revenues in 1981, $146.4 million was collected to pay new Federal taxes. Another $35.3 million was accounted for in franchise taxes, mainly to the cities of Calgary and Edmonton. Franchise taxes are levied on total revenues, including the Federal tax component; therefore, the new Federal taxes have meant a windfall for the cities at the expense of natural gas consumers. If the existing tax regime is maintained, the Company will have to collect from its customers in 1982 approximately

$360 million just to pay Federal excise tax, Petroleum and Gas Revenue Tax, the Federal Canadian Ownership Tax and franchise taxes. This tax burden weighs heavily on all customers but particularly on low income families in an area of the country where winters can be especially severe.

The Company welcomed during the year the energy agreement between the Federal and Alberta governments. The agreement at least has the effect of eliminating some of the uncertainties in energy development. Nevertheless, there does not appear to be sufficient incentive for oil and gas exploration firms, which continue to move their activities out of Canada. It will take time to assess the full impact of the agreement, but the initial indications are not encouraging.

At the time of writing, the future of the Alsands development north of Fort McMurray in Alberta Power's service territory is in question. The Imperial Oil Cold Lake project, also to be served by Alberta Power, is indefinitely postponed. However, regardless of setbacks in the megaprojects and the decline in conventional oil and gas exploration, the Company is encouraged by the continuing flow of new service applications and increases in system demand. Another source of encouragement is the expectation that the Alberta economy will grow faster than the Canadian average, sustained by a strong agricultural sector and large petrochemical projects. The Company forecasts 1982 growth in Alberta, measured in real gross domestic product, to be close to 4% compared to a negative rate (-1.5%) for Canada as a whole.

The Federal budget brought down in the fall of 1981 and its subsequent revision represents the biggest shake-up in our tax system since tax reform in 1971. The budget has eliminated most of the opportunities for individuals and corporations to reduce or defer taxes through various methods which were originally introduced for good reason in the name of equity. It is to be hoped that the Government responds to the demands of the Canadian people and brings in a new budget that will speed the recovery of the national economy.

Late in 1981 it was announced that the oil and gas assets owned by various ATCO Ltd. subsidiaries would be purchased by Canadian Utilities and combined with the non-utility operations of Canadian Utilities to form a new Alberta-based energy company. This company, to be known as ATCOR Resources Limited, is intended to become a significant participant in the petrochemical, and oil and gas exploration industries.

In the fourth quarter of 1981 the common share dividend was increased 11.5% to 34¢ ($1.36 on an annualized basis). This was the eleventh increase in the common share dividend in the past ten years.

In June 1981, William D. Grace, F.C.A., joined the Company as Senior Vice-President, Finance and was elected to the Board of Directors. In other senior management changes, Allan E. Scott joined the Company as a Vice-President; Harry N. Bottomley was appointed Vice-President and Controller; J. A. (Tony) Walker was appointed Treasurer; and Christopher K. Sheard was appointed General Counsel.

Five new Directors were elected to the Board at the annual meeting of shareholders on April 21, 1981: Basil K. French, Vernon L. Horte, Robert W. A. Laidlaw, D. M. (Max) Ritchie, and John D. Wood.

The past year brought its share of challenges and opportunities which were effectively met by the Company's employees. The successes of 1981 are a tribute to the skill and dedication of the 4,800 men and women who are Canadian Utilities Limited. To them the Directors express their sincere appreciation.

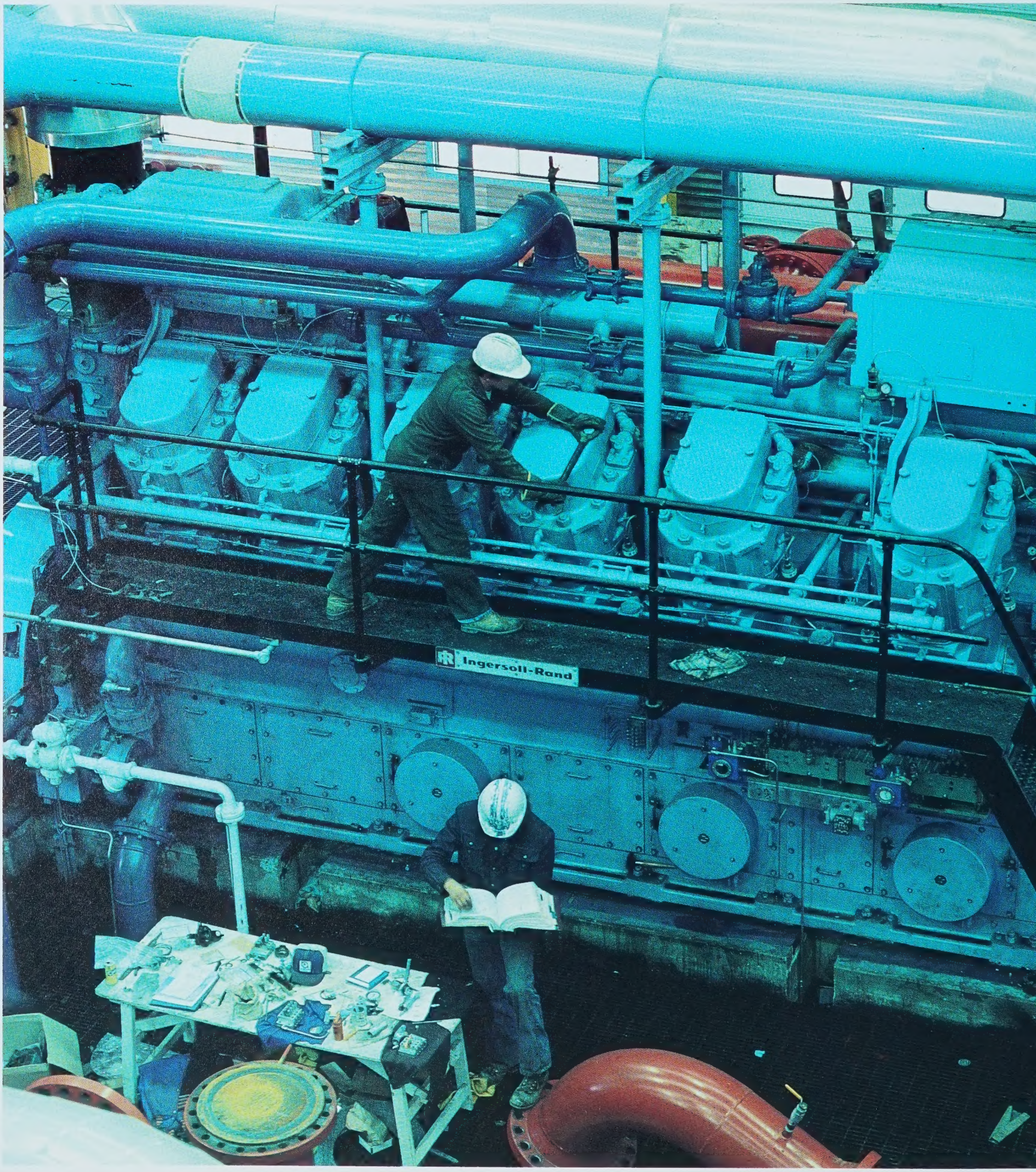
On behalf of the Board of Directors

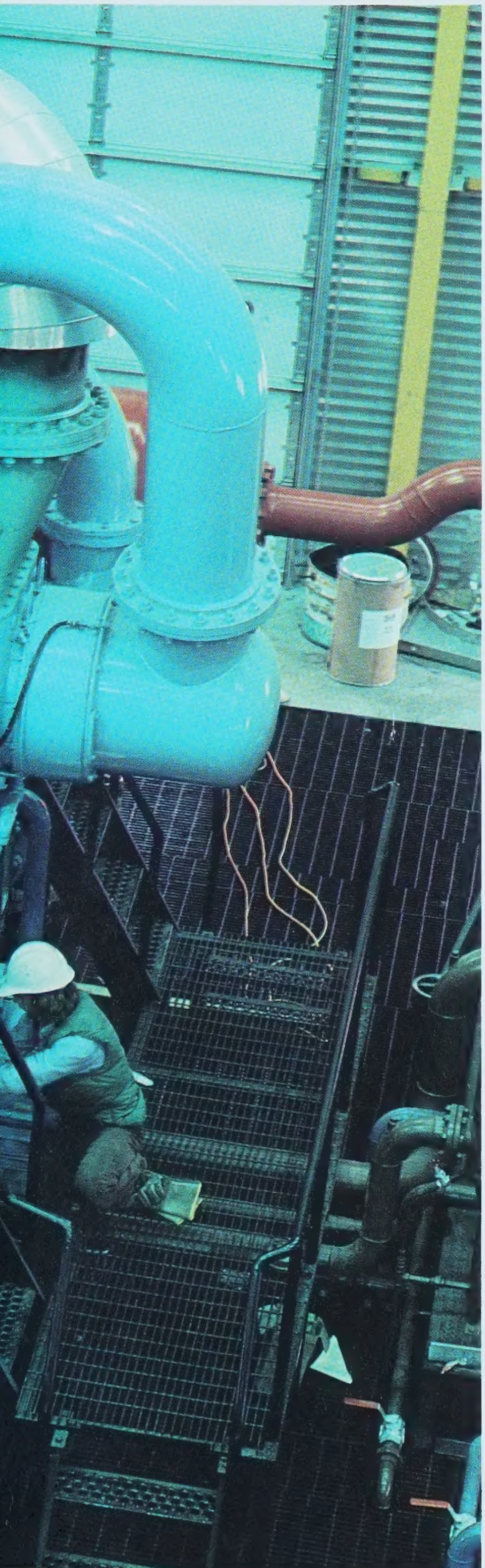
E. W. King

E. W. King,
President and
Chief Executive Officer

February 5, 1982

The largest compressor station in Northwestern Utilities' system commenced operations at the Viking Field, east of Edmonton, in October 1981. Shown in the photo is one of the station's two 2,600-horsepower compressor units used to move natural gas from the field to consumers.





NATURAL GAS OPERATIONS

Canadian Utilities' natural gas operations are conducted by two major natural gas utilities, Canadian Western Natural Gas Company Limited, which serves southern Alberta including Calgary and Lethbridge, and Northwestern Utilities Limited, which serves north-central Alberta including Edmonton, Red Deer, Fort McMurray, Grande Prairie and Camrose. A Northwestern Utilities subsidiary, Northland Utilities (B.C.) Limited, serves Dawson Creek and district in northeastern British Columbia.

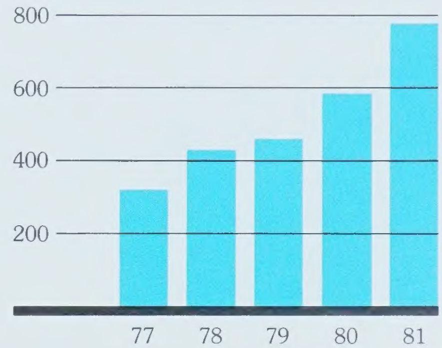
In spite of high interest rates and continued uncertainties in the energy industry, the natural gas operations continued to expand at a healthy pace with the addition of 29,776 customers, bringing the total to 549,773.

Net earnings in 1981 were $27.5 million compared to $20.6 million in 1980. Earnings attributable to common shares were $21.5 million ($1.02 per common share) compared to the previous year's $17.6 million ($0.84 per common share). The net fixed gas utility assets to serve customers increased to $481.8 million from $424.2 million in 1980.

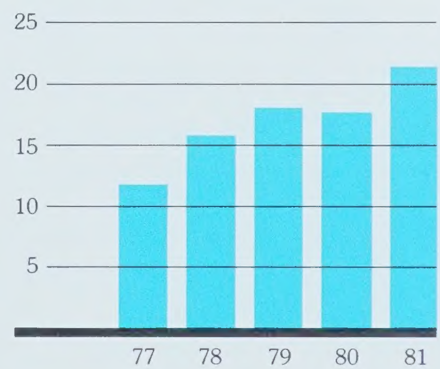
Rates

In early 1981, the Alberta Public Utilities Board established the rate of return for Canadian Western and Northwestern Utilities and gave final approval to rates as a result of May 1980 applications to recover increases in cost of service. Both Northwestern and Canadian Western obtained approval during 1981 for a system of

Natural Gas Revenues
(millions of dollars)



Net Earnings Attributable to Common Shares
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)

uniform rates for similar types of service together with metric energy billing, which took effect on January 1, 1982.

The National Energy Program established three new Federal taxes:

- The Natural Gas and Gas Liquids Tax was implemented at 28¢ per gigajoule (GJ) in November 1980 and increased to 42¢ per GJ on July 1, 1981.
- The Petroleum and Gas Revenue Tax of 8% of net production revenues was implemented January 1, 1981.
- The Canadian Ownership Tax of 14¢ per GJ was implemented May 1, 1981.

As these new taxes became effective, the Alberta Public Utilities Board and the British Columbia Utilities Commission acted expeditiously to hold public hearings and approve the passing on of the costs.

Rate decreases for both Northwestern and Canadian Western were approved, effective November 1981, following a reduction in the Alberta Border Price and subsequent change in the Provincial support price for natural gas.

The British Columbia Utilities Commission authorized an increase in rates effective August 1981 for Northland customers to meet an increase in the wholesale price of natural gas and increases in the costs of service.

Costs and Revenues

Consolidated natural gas revenues were $779.2 million, $197.5 million higher than in 1980. Operating expenses, including the cost of natural gas, operations, maintenance, depreciation and taxes other than income tax, amounted to $728.1 million, compared to $538.1 million in 1980. The Company's largest expenses are natural gas and the new energy related taxes. During the year, gas costs rose by $36.4 million to $442.2 million. Gas costs were net of $79.1 million in rebates received from the Alberta Government under the Natural Gas Price Protection Plan. Rebates totalled $117.8 million 1980.

The new Federal taxes resulting from the National Energy Program totalled $146.4 million, an increase of $127.6 million from 1980. Municipal and franchise taxes paid to municipalities were $38.4 million, an increase of $10.7 million from the previous year. Provincial Mineral Taxes increased from $0.6 million to $0.9 million in 1981.

Total taxes from gas operations, including income taxes, paid to all levels of government increased $140.2 million to $194.9 million in 1981 and amounted to 25.0% of revenue as compared to 9.4% in 1980. The Federal energy taxes are especially onerous to gas consumers in Alberta, given the severity of the climate and dependence on natural gas for home heating.

The combined total of natural gas sold and transported was 423,534 terajoules (TJ), compared to 434,286 TJ in 1980. Natural gas sales decreased by 5% to 372,364 TJ. Growth in usage because of increased numbers of customers was more than offset by warmer than normal temperatures, energy conservation, and lower sales to industrial customers.

The average temperature in Alberta in 1981 was the warmest in the last 100 years since official government records have been kept. In terms of degree days — a measure of space heating requirements — 1981 was

Cost Increases

	($ Millions)			%
	1981	1980	Increase	Increase
Natural Gas Supply . . .	**$442.2**	$405.8	$ 36.4	9.0
Operating, Maintenance and Depreciation . . .	**100.3**	85.2	15.1	17.7
Total Taxes	**194.9**	54.7	140.2	256.3
Interest and Net earnings less AFUDC*	**41.8**	36.0	5.8	16.1
TOTAL	**779.2**	581.7	197.5	34.0

* Allowance for Funds Used During Construction

17.7% warmer than normal in Northwestern's service area and 17% warmer than normal in Canadian Western's territory. The previous year had been from 2.3% to 4% warmer than normal.

Energy conservation is continuing to reduce sales in most market segments. Usage per residential customer is declining because of customer conservation efforts together with an increasing proportion of better insulated, smaller multiple-family housing units.

During 1981 gas transported through Canadian Western's and Northwestern's transmission facilities for exporting companies for delivery to the Nova system, and for industrial consumers for delivery to their plant sites, was 51,170 TJ compared to 42,311 TJ in 1980.

Capital Expenditures

Gas operations capital expenditures were $81 million in 1981 compared to $76 million the year before. Among the major projects were the completion of Northwestern's 5200-horsepower compressor station at the Viking Field, improving the utility's capacity to meet customer requirements and transportation exchange agreements. Northwestern also began work on the installation of 55.5 km of 89 mm to 273 mm pipe in the second phase of the Wainwright-Auburndale gathering system to tie in 14 wells. This project will extend into 1982.

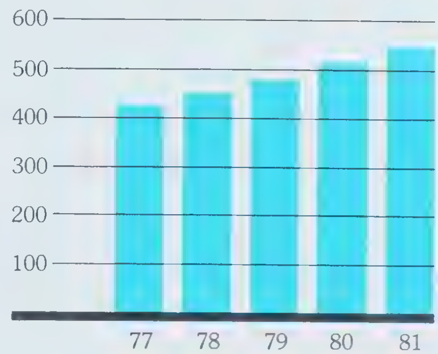
Canadian Western tied into its system seven new wells in the Carbon area. Also, Canadian Western received approval from the Energy Resources Conservation Board to build a 24 km, 406.4 mm transmission line from the Nova pipeline system in the Priddis area to Canadian Western's transmission facilities south of Calgary. Construction of the line is expected to be completed in 1982.

During 1981 Canadian Western purchased the assets of the Valley Gas Company serving 840 customers in the communities of Turner Valley, Longview and surrounding rural area in the Municipal District of Foothills No. 31. An agreement was also reached with the municipality of Bow Island for the purchase of its distribution system, serving 674 customers. Canadian Western has operated this system since January 6, 1982, and expects to complete the purchase following a franchise hearing before the Public Utilities Board.

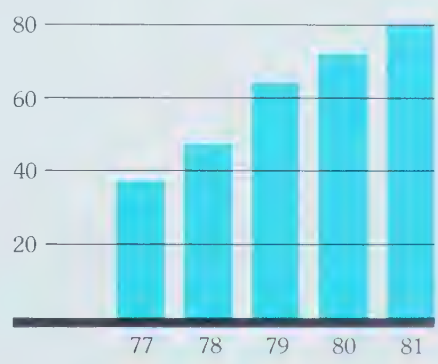
Construction of Canadian Western's head office at 8th Street and 11th Avenue S.W., Calgary started in August and the building is scheduled to be ready for occupancy in September of 1982. An operations centre in the Midnapore area was constructed in 1981 and will serve customers in the southern part of Calgary. Canadian Western also started construction in November on a new operations centre in northeast Calgary in the Whitehorn area, with completion planned for the summer of 1982.

Natural Gas Sales
(petajoules)

Natural Gas Customers
(thousands)



Capital Expenditures
(millions of dollars)



Gas Supply

The major portion of the utilities' supplies of natural gas is purchased under long-term contracts with producing companies. The balance is supplied from a combination of purchases from export and pipeline companies or are obtained from company-owned producing properties. The utilities also utilize natural gas storage for supply system balancing.

Recent estimates indicate that the Company owned 914 petajoules and had under long-term contract 3,330 petajoules of energy in the form of gas reserves from fields from which it purchases natural gas; and that an additional 2,460 petajoules will be available for purchase in the future from oil field gas caps connected to the utilities' transmission systems and from fields where the estimated gas producing life exceeds the term of the existing gas purchase contracts.

The utilities pursue programs involving the acquisition, exploration and development of additional natural gas properties and supplies. In addition, to ensure that future supply requirements are met, there are agreements with five major export companies which enable the utilities to call upon these gas exporters for quantities of base-load and peak-load gas as required. The security of the natural gas supply is also assisted by the policy of the Alberta Government whereby local customers have priority over out-of-Province demands for natural gas.

The exploration and development program increased considerably compared to 1980 with the utilities participating in the drilling of 115 wells and the purchase of an additional 13 wells. Of the wells drilled, 83 were successful or are still being evaluated. The cost of successful wells was added to assets; the cost of unsuccessful projects will be recovered, with Public Utilities Board approval, from border flowback funds. Under the border flowback program, all Alberta gas producers, including Canadian Western and Northwestern, receive a pro rata share of the extra revenues generated by the differential in price between gas exported to the U.S. and that marketed in Canada.

Gas Operations Earnings Contribution

	1981	1980	1979	1978	1977	1976	Annual Growth Rate 1976-81
			(Millions of dollars)				(Per cent)
Natural gas revenues	**779.2**	581.7	477.9	431.8	318.7	216.5	29.2
Operating expenses							
Natural gas supply	**442.2**	405.8	342.3	315.5	221.3	134.8	
Operating and maintenance	**86.4**	73.3	61.1	49.7	42.8	36.3	
Taxes — other than income	**185.6**	47.1	23.4	22.5	18.1	14.3	
Depreciation	**13.9**	11.9	10.3	8.9	7.1	6.6	
	728.1	538.1	437.1	396.6	289.3	192.0	30.6
	51.1	43.6	40.8	35.2	29.4	24.5	15.8
Income deductions	**14.3**	15.4	10.5	8.5	8.9	7.6	
Income taxes	**9.3**	7.6	9.2	8.0	6.4	5.3	
Net earnings	**27.5**	20.6	21.1	18.7	14.1	11.6	18.8
Preferred dividend requirements	**6.0**	3.0	3.0	3.0	2.4	.5	
Balance attributable to common shares	**21.5**	17.6	18.1	15.7	11.7	11.1	13.7
Mid-year common equity investment	**117.9**	109.2	100.3	86.7	75.5	68.3	11.5

Natural Gas System

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES LIMITED

MAJOR TRANSMISSION AND FIELD GATHERING PIPELINES

MAJOR PIPELINES OWNED BY OTHERS

Electric sales to retail customers rose 7.4% in 1981 to 3,216 million kilowatt hours. With the commencement during the year of the sale of half the output of the new Battle River Unit #5 to the City of Edmonton, wholesale sales attained a significant level of 495.2 million kilowatt hours.

ELECTRIC POWER OPERATIONS

The Company's major electric power subsidiary, Alberta Power Limited, now serves 375 communities in east-central and northern Alberta and five communities in the Northwest Territories including the Town of Hay River. An Alberta Power subsidiary, The Yukon Electrical Company Limited, serves 19 communities in the Yukon including the City of Whitehorse.

In 1981, 5,785 new customers were added, bringing the year-end total to 134,602. Included in this number were 24,787 farm customers of whom 23,062 were members of 158 Rural Electrification Associations.

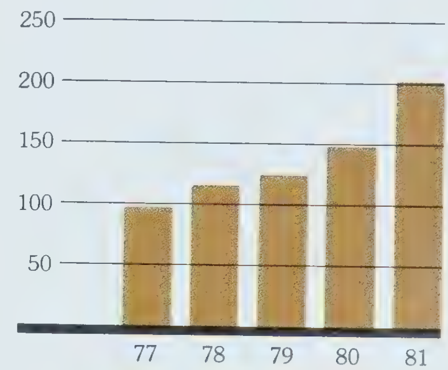
Energy sales to ultimate customers increased by 7.4% to 3,216 million kilowatt hours. An additional 495 million kilowatt hours were sold to other utilities. The peak load increased to 652 megawatts from 607 megawatts the previous year.

The following table shows 1981 electric sales to the various customer categories (not including 495 million kilowatt hours sold to other utilities).

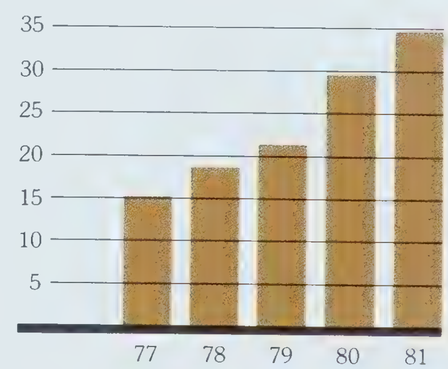
	Thousands of Kilowatt Hours	Per Cent of Total
Industrial	1,636,390	50.9
Commercial	643,706	20.0
Residential	581,146	18.1
REA and others	354,703	11.0
TOTAL	3,215,945	100.0

Electric revenues were $202.2 million, up from $150.3 million in 1980. This growth in revenue was a result of increased sales and of increases in rates of 12% effective January

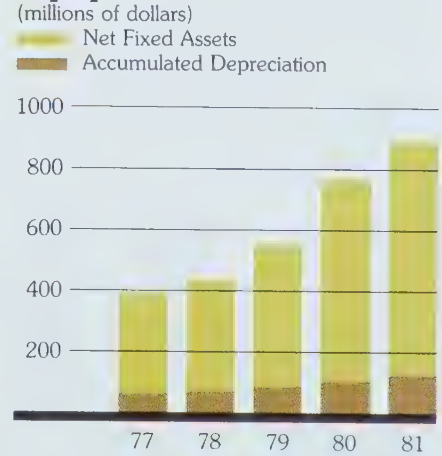
Electric Revenues
(millions of dollars)



Net Earnings Attributable to Common Shares
(millions of dollars)



Property, Plant and Equipment
(millions of dollars)



1, 1981 and 16% effective October 1, 1981.

Earnings attributable to common shares were $34.5 million ($1.07 a common share) compared to $29.4 million (91¢ a common share) in the previous year.

In August 1981, the Public Utilities Board of Alberta issued an order concerning the application filed by Alberta Power in October 1980. The order found that a reasonable return on common equity for the years 1980 and 1981 would be 14.75%. Following this order, Alberta Power applied for permission to readopt the Normalization — All Taxes Paid method of accounting for income taxes and received Board approval for a 16% increase in rates effective October 1, 1981.

Faced with the full impact of Battle River #5 in the rate base in 1982 and with increases in operating costs, the cost of capital and income taxes, Alberta Power filed an application with the Board for increased rates effective January 1, 1982. Pursuant to a hearing on January 14, 1982 the Board allowed interim refundable rates to be put into effect February 1, 1982. These rates contain approval, on a interim basis, for a return on common equity of 16.5%

Construction Activity

Alberta Power expenditures for additions to property, plant and equipment during the year were $154 million. Of this, the largest single amount, $40 million, was spent on the completion of Battle River #5. This 375-megawatt unit was commissioned during the year and was officially opened September 16, 1981. Battle River #5 brought Alberta Power's total installed generating capacity to 1,054 megawatts. Half of the unit's output is being sold to the City of Edmonton under a contract expiring in 1988. In addition, a second 45-cubic metre dragline was commissioned during the year, and is being used to mine coal for the Battle River Station at the newly opened Paintearth Mine.

The total expenditure on transmission projects was $30.4 million. Major projects included a 136-kilometre, 240-kilovolt line from Battle River via Sheerness to Brooks ($14.9 million); an 80-kilometre, 144-kilovolt line from Peace River to Friedenstal ($6.4 million); and a 50-kilometre, 144-kilovolt line from High Level to Rocky Lane ($2.1 million).

Other major transmission projects which are currently planned or underway include a 115-kilometre, 144-kilovolt line from Crystal Lake to Friedenstal with a substation ($7.4 million); a 125-kilometre, 240-kilovolt line from Louise Creek to Mitsue ($21.6 million); and the Anderson substation to be constructed at the site of the Sheerness Generating Station ($26.5 million).

By the end of 1981, construction was well underway on the cooling pond and powerhouse at the Sheerness Generating Station. As the 750-megawatt Sheerness Station will have capacity surplus to Alberta Power's needs, an agreement has been entered into with another utility to share on an equal basis in the ownership of the plant, with Alberta Power acting as the managing owner. In 1981, Alberta Power's 50% share of the expenditures was $30 million. The first unit is scheduled to be commissioned in 1985 with the second unit to follow in 1986.

Future Development

Although the Federal and Alberta governments reached an accord on oil pricing during 1981, and oil production has returned to its pre-March 1981 levels, exploration and service activity in Alberta Power's service area remain depressed, following the announcement of the National Energy Program in October 1980. In addition, the decision to place the Esso Resources Cold Lake project

on hold and delays surrounding the Alsands project have created uncertainty in the planning required to supply these customers, and inhibited the anticipated growth of supply industries in the Cold Lake and Fort McMurray areas. In addition, the decision of the Federal Minister of Transport to abolish transcontinental train service through Edmonton is expected to have an adverse affect on the tourist industry in Jasper, which Alberta Power serves.

Capital expenditures of $157 million are anticipated in 1982. Of this, $76 million relates to Alberta Power's 50% share of the Sheerness Generating Station. A further $46 million will provide additional transmission lines with $42 million being required for distribution lines and other facilities.

During 1981 the Alberta Energy Resources Conservation Board allowed Alberta Power to extend its service area south from the Fort McMurray area to Township 77. This area, although less than applied for, has potential for heavy oil or in situ tar sands plants.

In November 1981 the Alberta Government announced Bill 92 to establish the Electric Energy Marketing Agency. This Agency is to act as a vehicle for the Province-wide equalization of generation and transmission cost, by purchasing energy at the utilities' cost and reselling at the system-wide average cost.

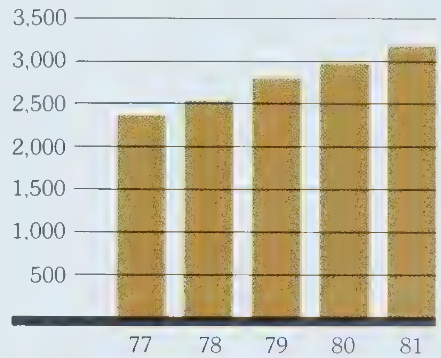
In addition the Agency will be responsible for the import of power into the Province. Although regulations have not yet been drawn up, it appears that Alberta Power's customers in the Province will be beneficiaries of the plan.

Territories

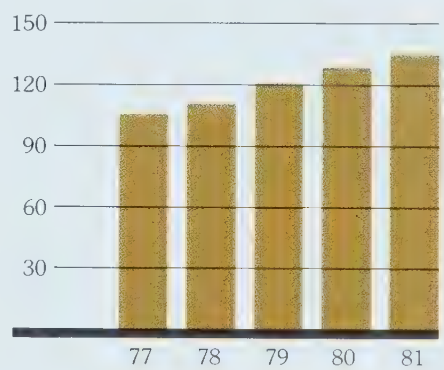
Regulatory authorities permitted a 7% rate increase in the Yukon effective June 1, 1981 and a 9% increase in the Northwest Territories effective October 1, 1981. Fuel adjustment clauses in both territories enable fuel cost increases to be passed on to customers without the necessity of formal hearings.

A submission is being prepared to the Yukon Territory Water Board to construct a 750-kilowatt hydroelectric unit on McIntyre Creek near Whitehorse at an estimated cost of $3 million. During the year a subcommittee of the House of Commons held hearings throughout the Yukon and Northwest Territories on the structure of the electric utility industry in the North. Company briefs were presented to the subcommittee on both the Yukon and Northwest Territories operations, emphasizing the need to be able to construct generating facilities of an off-oil nature, in order to provide dependable and affordable service to its customers north of 60°.

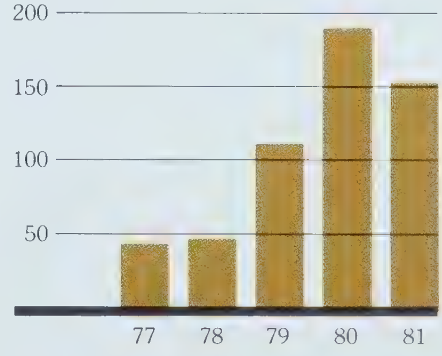
Electric Sales
(millions of kilowatt hours)



Electric Customers
(thousands)



Capital Expenditures
(millions of dollars)

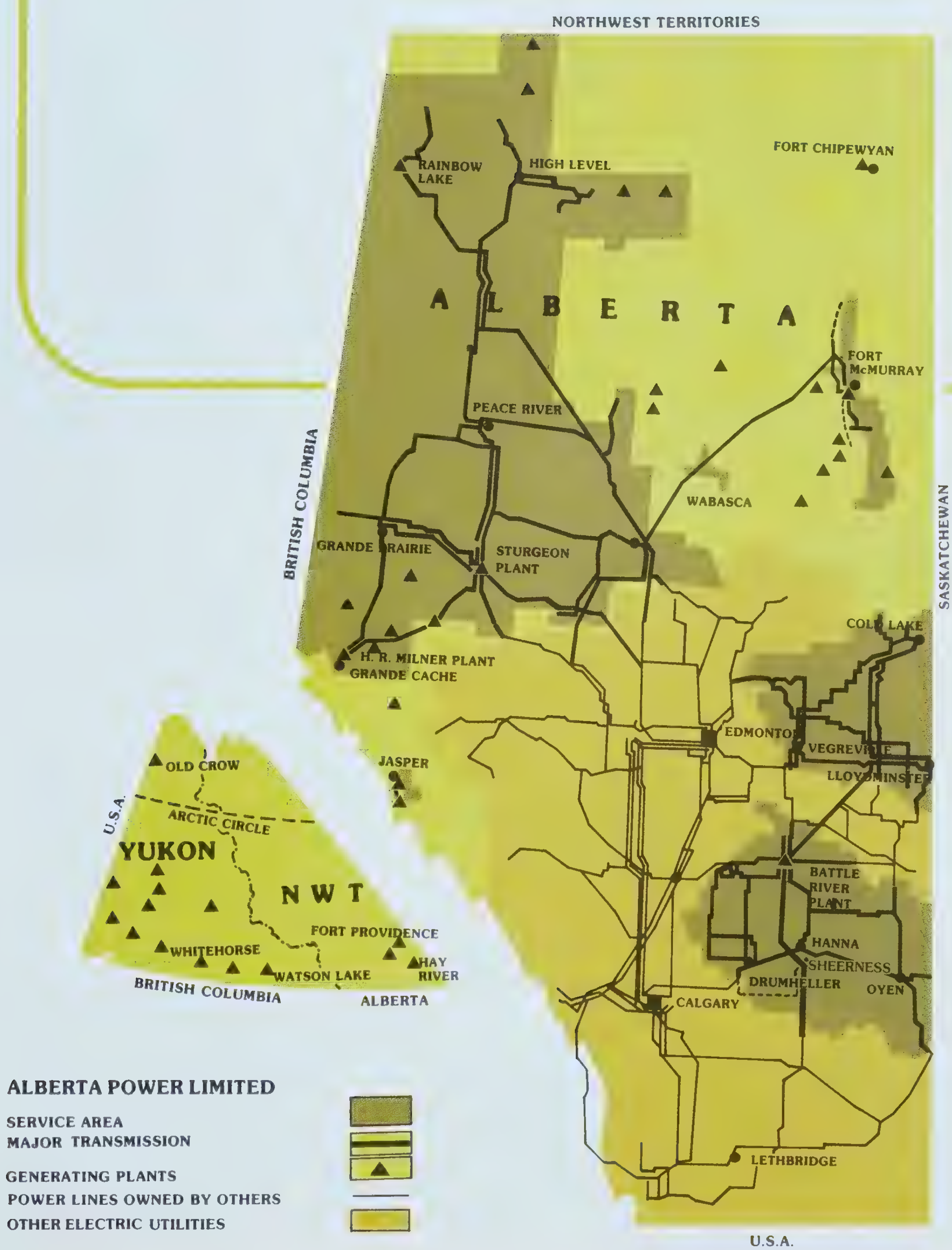


Work proceeds on the cooling pond dyke and below ground facilities at the site of the Sheerness Generating Station. The first of the plant's two 375-megawatt units is scheduled to be commissioned in 1985.

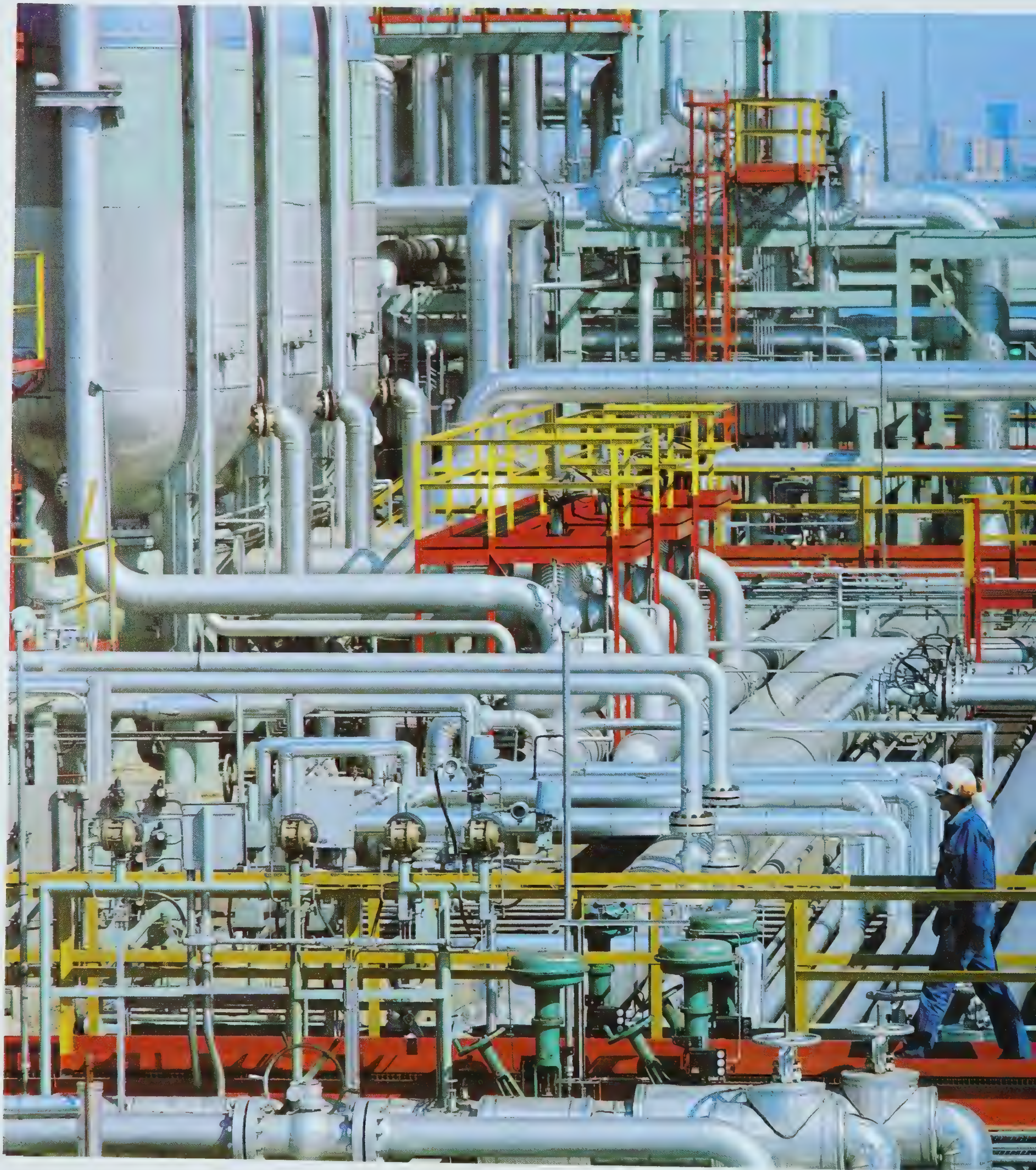
Electric Operations Earnings Contribution

	1981	1980	1979	1978	1977	1976	Annual Growth Rate 1976-81
			(Millions of dollars)				(Per cent)
Electric revenues	**201.7**	149.8	124.6	114.7	93.9	78.1	20.9
Operating expenses							
Operating and maintenance	**93.5**	74.4	61.7	51.9	42.3	35.4	
Taxes — other than income	**7.2**	5.1	4.5	4.2	3.7	2.7	
Depreciation	**21.1**	16.0	14.6	13.8	11.4	8.8	
	121.8	95.5	80.8	69.9	57.4	46.9	21.0
	79.9	54.3	43.8	44.8	36.5	31.2	20.7
Income deductions	**12.3**	3.9	9.1	8.7	10.2	12.3	
Income taxes	**17.8**	11.8	6.7	11.1	5.8	3.1	
Net earnings	**49.8**	38.6	28.0	25.0	20.5	15.8	25.8
Preferred dividend requirements	**15.3**	9.3	6.3	6.3	5.1	3.0	
Balance attributable to common shares	**34.5**	29.3	21.7	18.7	15.4	12.8	21.9
Mid-year common equity investment	**198.5**	181.3	149.7	113.2	98.8	84.8	18.5

Electrical System



Up to 9.6 million cubic metres of natural gas a day are delivered from Northwestern Utilities' transmission system to the CU Ethane-Dome Petroleum ethane extraction plant in Edmonton.



PETROCHEMICALS
RESOURCE DEVELOPMENT
CONSULTING ENGINEERING

CU Ethane Limited

CU Ethane is the joint owner with Dome Petroleum Limited of an ethane extraction plant situated in Edmonton. Ethane is removed from natural gas flowing into Edmonton through Northwestern Utilities' transmission system.

During 1981 the plant produced 698,400 cubic metres of ethane and 483,300 cubic metres of natural gas liquids. Ethane is used as feedstock for the production of ethylene.

To date CU Ethane's 50% share of the return on the total $45 million investment in the plant has been determined on a guaranteed cost of service basis. Commencing July 1, 1982 CU Ethane (or its successor company) will exercise its option to share with Dome in the profits from the marketing of the natural gas liquids (propane pluses). This arrangement is expected in the long term to add significantly to earnings from non-utility operations.

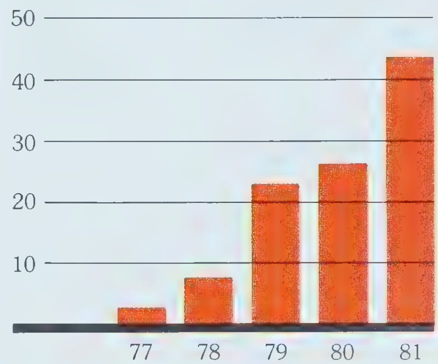
CU Resources Limited

During 1981 CU Resources carried on its search for oil and gas in Alberta and northeastern British Columbia.

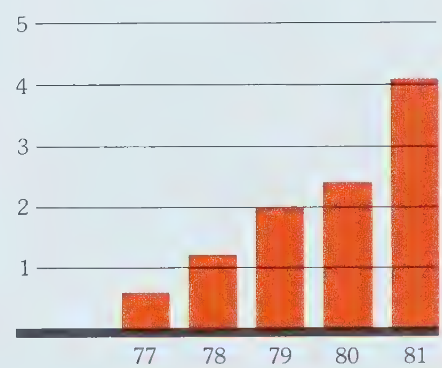
The Company participated in the drilling of five wells of which three were completed as oil wells and two were unsuccessful.

At year end, CU Resources had net land holdings of 16,350 acres and net reserves of 275,000 cubic metres of oil and 70.4 million cubic metres of natural gas. Production for the

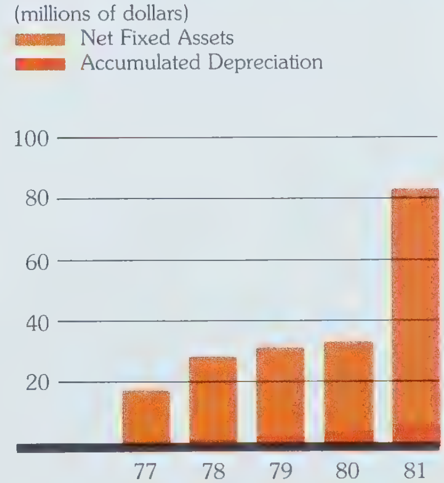
Other Revenues
(millions of dollars)



Net Earnings Attributable to Common Shares
(millions of dollars)



Net Fixed Assets
(millions of dollars)



year totalled 26,500 cubic metres of oil and 2.96 million cubic metres of natural gas.

During the year CU Resources began providing natural gas service to large consumers on a gas brokerage basis, arranging for the purchase, transportation, and exchange of gas, as required, to fulfill the needs of large consumers. During 1981, CU Resources gas brokerage operations involved the sale of 9,800,000 gigajoules to four large industrial customers.

CU Engineering Limited

CU Engineering was engaged in the following major projects during 1981.

- Project management, including engineering and construction supervision, for an oil and gas pipeline project at the Syncrude plant near Fort McMurray.
- Preliminary design and feasibility study for a major gas distribution network through the Province of New Brunswick.
- Engineering for a gas transmission line in northern Alberta for a tar sands pilot project north of Fort McMurray.
- Engineering work on several gas transmission and distribution systems for rural gas co-operatives in Alberta.

CU Engineering clients include government and municipal agencies, oil and gas producers, and other utility companies outside of the Canadian Utilities Group. Although CU Engineering's market area is principally the Province of Alberta, in 1981 the Company's activities reached across Canada and as far as Southeast Asia.

CU Engineering provides consulting services, including feasibility studies, design, construction supervision and commissioning of utility systems. These systems include gas, electric and sewer and water systems. In addition, the Company offers engineering services related to oil and gas pipelining and production and primary treatment facilities.

In addition to its own professional staff, CU Engineering has access to professional and technical staff from the affiliated Canadian Utilities companies.

Proposed Amalgamation

As mentioned elsewhere in this report, Canadian Utilities Limited intends to amalgamate all of its existing non-utility operations including CU Ethane, CU Resources and CU Engineering and 281159 Alberta Ltd., which owns oil and gas interests and other assets previously owned by three ATCO Ltd. subsidiaries.

The corporation resulting from such an amalgamation, to be known as ATCOR Resources Limited, would provide a single vehicle for participating in a wide range of non-utility, non-regulated resource-related investment opportunities, primarily in Alberta.

Financial Review

Alberta Power's Battle River plant, located adjacent to abundant coal deposits near Forestburg in southeastern Alberta, was expanded to a total capacity of 741 megawatts with the commissioning in August of the 375-megawatt Unit #5.

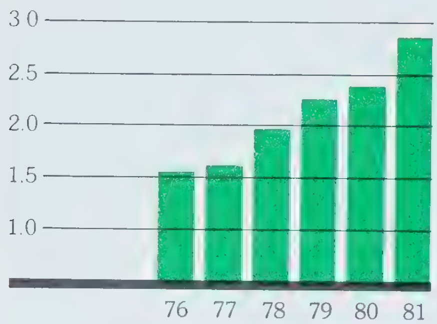
Earnings

The Company recorded earnings of $2.87 per common share in 1981, representing a 21% increase over the previous year's $2.37. The number of common shares outstanding at the year-end increased from 20,818,000 to 22,968,000 shares. This converted to a weighted average of 20,911,000 shares for the entire year.

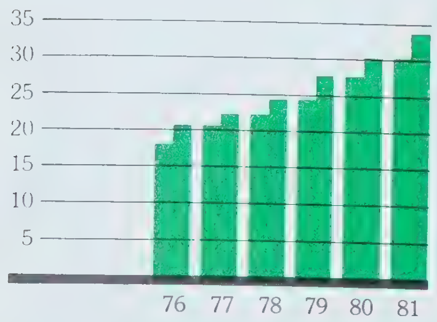
The total net earnings for 1981 were $81,437,000, an increase of 32% from the previous year. After provision for preferred dividend requirements, the Company reported earnings attributable to common shares of $60,096,000 as compared to $49,273,000 in 1980, an increase of 22%. The electric utilities contributed appoximately 57% to these earnings, while the gas utilities accounted for 36% and non-utility business provided 7%.

The Company's increase in net earnings continues to reflect the rapid growth of the utility rate base resulting from strong demand for utility services. This factor, combined with an increase in non-utility earnings, served to more than offset the unfavourable effects of warmer than normal temperatures and the escalating costs of providing utility service.

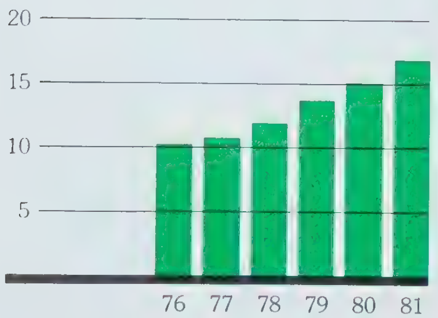
Earnings Per Share
(before extraordinary items fully diluted in dollars)
Annual Growth Rate 13.1%
(1976 - 1981)



Dividends Per Common Share
(quarterly rate)
Annual Growth Rate 12.9%
(1st quarter 1976 to 4th quarter 1981)



Shareholders' Equity
(dollars per common share)
Annual Growth Rate 10.7%
(1976 - 1981)



Earnings Per Common Share

	1981	1980	Gain in 1981	
	$	$	$	%
Electric	**1.65**	1.41	0.24	17
Natural Gas	**1.02**	0.84	0.18	21
Other	**0.20**	0.12	0.08	67
Total:	**2.87**	2.37	0.50	21

Growth in Net Earnings Attributable to Common Shares

	$ Millions			
	Electric	Natural Gas	Other	Total
Five-Year Compound Growth Rate	21.9%	14.7%		20.5%
1981	$34.5	$21.4	$4.2	$60.1
1980	29.3	17.6	2.4	49.3
1979	21.7	18.1	2.0	41.8
1978	18.7	15.7	1.2	35.6
1977	15.4	11.7	0.6	27.7
1976	12.8	10.8	0.1	23.7

In total, the utility cost of service rose $246 million to $990 million in the year. The major factor contributing to this increase was the imposition of new energy taxes levied by the Federal Government: the Federal Canadian Ownership Tax and the Petroleum and Gas Revenue Tax. These taxes, when combined with the full year effect of the Federal excise tax introduced with the National Energy Program in 1980, accounted for approximately 50% of the cost of service increase and were reflected in natural gas billing during the year. Natural gas supply purchases, which have traditionally been a major factor in cost of service increases, contributed only 15% to the increase. The remainder of the increase is attributable to the rising cost of labour, supplies, investment capital and other taxes.

Distribution of Earnings

The Company's financial rate of return on fully diluted average common equity was 16.7%, a figure that was consistent with the previous five-year period. The Company paid out total dividends of $1.255 per common share in 1981. The common dividend per share amounted to 30.5 cents in each of the first three quarters of the year and 34 cents in the final quarter. This was consistent with the Company's policy of paying out approximately 50% of earnings and reinvesting the balance in the Company.

Capital Expenditures

Capital expenditures in 1981 on new plant and equipment were $235 million of which $40 million was expended on construction of the recently commissioned Battle River Generating Unit #5. This unit was completed in 1981 at a total project capital cost of $255 million.

The Company also committed $30 million to construction of the Sheerness Generating Station. The Company expects to invest a total of $500 million on its 50% share of this $1 billion project. The station's two units are scheduled to be commissioned in 1985 and 1986.

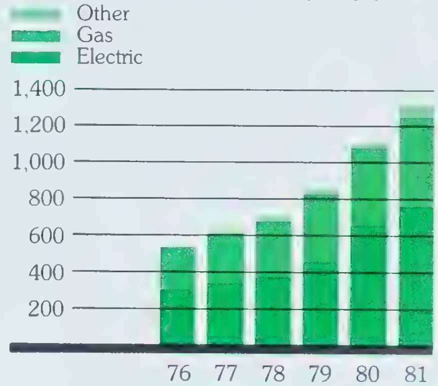
The Company forecasts that its capital program will exceed $1.8 billion during the forthcoming five-year period. Included in this figure is $325 million that will be invested in new plant and equipment in 1982. This forecast level of spending may, however, be adjusted downward if the Province's major energy-related projects do not proceed as planned.

Financing

In 1981, the Company successfully arranged external financings totalling $210 million. Such financing included a $30 million floating rate note and two issues of preferred shares, one in February amounting to $55 million at a 10.12% dividend rate, the other in October for $75 million at a 14.00% dividend rate. The Company also undertook its first European financing in December, a $50 million debt issue in Canadian funds, with a 15-year maturity and an annual coupon rate of 17%. The issue is listed on the London Stock Exchange and was well received by the European financial community. Subsequent to year-end the Company issued

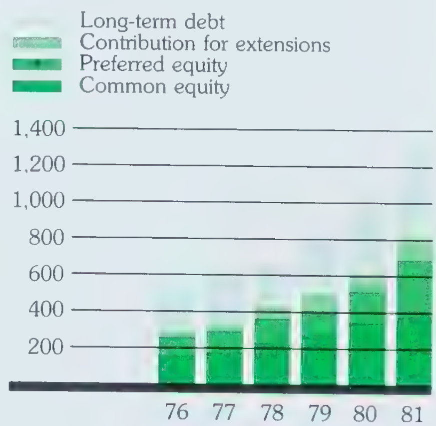
Asset Distribution by Type of Business

(net fixed assets in millions of dollars)
5 Year Growth Rates
Total 19.4% Electric 20.4% Gas 14.8%



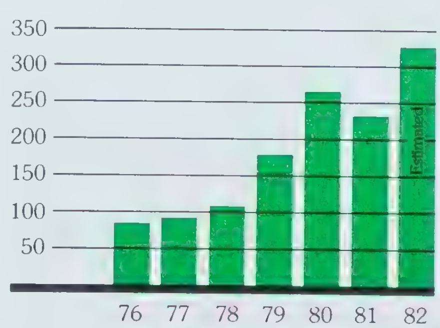
Invested Capital

(millions of dollars)
*including minority interest



Capital Program

(millions of dollars)



Capital Expenditures

	1981 ($ millions)	1982 Forecast ($ millions)
Electric	153.5	157.3
Natural Gas	80.9	167.6
Other	0.7	—
Total	235.1	324.9

a further series of preferred shares, amounting to $50 million at a 14.5% dividend rate.

The Canadian financial market continues to be plagued by high interest rates and an uncertain inflation outlook. Consequently the Company will continue to monitor the U.S. and European financial markets with the intent of entering these markets if conditions are favourable.

Funds from operations, after providing for common and preferred dividends, amounted to $77.1 million in 1981, an increase of more than 28% over the previous year.

The rapid rate of customer and energy sales growth will mean that significant amounts of investment will be required in the future to meet the demand for utility services. The Company will continue to rely on the financial markets to fund a large portion of this growth. Recognizing this fact the Company has an appropriate capitalization structure that allows it to maintain its high credit rating on senior debt securities, thereby allowing it to finance at the lowest rates possible. The Company's debt instruments are rated AAA and A+ by the two major Canadian rating firms.

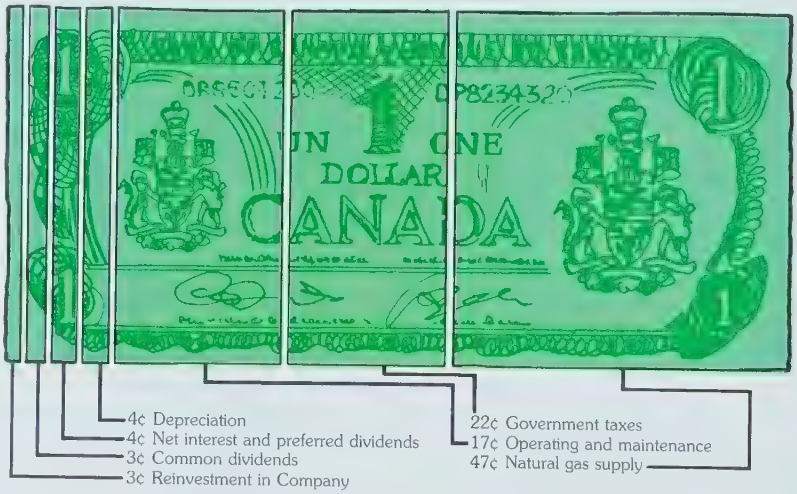
Regulatory Environment

The operations sections of this report contain details of regulatory applications during the past year. Rate applications included requests for an increase in the rate of return on common equity deemed to be financing the rate base. The applications included a two-year test period in 1980 and 1981 and sought a 15.5% rate of return on common equity, approximately 1.25% above the last rate allowed by the Public Utilities Board of Alberta. The Board subsequently approved a 14.75% rate of return on common equity for all subsidiary utilities for 1981.

The electric utility has requested a 17.25% equity return in its 1982 submissions to the Board, made in November 1981, while the gas utilities are expected to file for a comparable return in early spring. Alberta Power recently received a Board order for interim refundable rates which, among other things, granted a 16.5% utility return on common equity for 1982. The Board indicated in its interim order that "upon full and final determination, it is conceivable that the 17.25% rate forecast by APL (Alberta Power) may be considered to be appropriate". This comment is significant and indicates that the Board recognizes the importance of providing adequate rates of return in order to preserve the integrity of present shareholders and to attract new capital.

Where the Revenue Dollar was Spent

During 1981, 22% of total revenue was earmarked for the payment of government taxes. Energy supply purchases accounted for 47% of total revenue distribution, and were down in near direct proportion to government tax increases. After-tax profit margins maintained a percentage share consistent with the previous year.



Financial Statements

A Canadian Western Natural Gas crew prepares a reel of plastic service line, which will be installed in a new Calgary subdivision. Both Canadian Western Natural Gas and Northwestern Utilities introduced plastic distribution and service line to urban areas during 1981.

Management's Responsibility for Financial Reporting

The consolidated financial statements and other financial information relating to the Company contained in this Annual Report have been prepared by management, which is responsible for the integrity and objectivity of this information. The financial statements have been prepared in conformity with generally accepted accounting principles as applied to regulated utilities and necessarily include some amounts that are based on informed judgments and best estimates of management.

Management depends upon a system of internal accounting controls to meet its responsibility for reliable and accurate reporting, which includes periodic reviews by the internal audit function. Management modifies and improves its system of internal accounting controls in response to changes in business conditions.

Price Waterhouse, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements. Their examination is conducted in accordance with generally accepted auditing standards and includes tests and other procedures which allow them to report on the fairness of the consolidated financial statements prepared by management.

Four non-management directors of the Company serve as the Audit Committee. The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters and to gain assurance that they are carrying out their responsibilities. The internal auditors and the independent auditors have full and free access to the Audit Committee.

Auditors' Report

To the Shareholders of Canadian Utilities Limited:

We have examined the consolidated balance sheet of Canadian Utilities Limited as at December 31, 1981 and the consolidated statements of earnings and retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1981 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants

Edmonton, Canada
February 1, 1982

Canadian Utilities Limited

Consolidated Statement of Earnings and Retained Earnings

Year ended December 31, 1981 with comparative figures for 1980

	1981	1980
	(Thousands)	
Revenues	**$1,024,564**	$757,696
Operating Expenses		
Natural gas supply (Note 1)	**442,152**	405,832
Operating and maintenance	**212,477**	166,284
Taxes — other than income (Note 2)	**195,834**	53,160
Depreciation	**36,782**	29,485
	887,245	654,761
	137,319	102,935
Allowance for Funds Used During Construction	**24,579**	19,653
Other Income	**6,759**	2,660
	168,657	125,248
Interest Expense	**53,669**	39,496
	114,988	85,752
Income Taxes (Note 3)	**30,625**	21,584
	84,363	64,168
Minority Interests	**2,926**	2,555
Net Earnings	**81,437**	61,613
Retained Earnings at Beginning of Year	**124,949**	99,059
	206,386	160,672
Deduct:		
Dividends (Note 11)	**46,989**	35,723
Write-off of undertakings, franchise and gas rights	**8,000**	
Retained Earnings at End of Year	**$ 151,397**	$124,949
Earnings — Dollars per Common Share	**$ 2.87**	$ 2.37

Canadian Utilities Limited

Consolidated Balance Sheet

December 31, 1981 with comparative figures for 1980

	1981	1980
	(Thousands)	
ASSETS		
Current Assets		
Cash and short-term deposits	**$ 43,482**	$ 2,565
Accounts receivable (Note 4)	**175,540**	171,342
Materials and supplies — at average cost	**19,352**	16,941
Natural gas stored — at cost	**832**	1,894
Prepaid expenses	**2,982**	7,832
	242,188	200,574
Property, Plant and Equipment (Note 5)	**1,318,523**	1,083,681
Deferred Expenses (Note 6)	**42,029**	29,833
	$1,602,740	$1,314,088
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Due to bank	**$ 30,859**	$ 25,308
Accounts payable and accrued liabilities	**165,286**	166,319
Income and other taxes	**37,166**	24,854
Dividends payable	**5,514**	2,883
Long-term debt — current maturities	**6,967**	3,556
Deposits	**2,644**	2,314
	248,436	225,234
Notes Payable (Note 7)	**30,000**	60,000
Long-Term Debt (Note 8)	**453,342**	393,611
Contributions for Extensions to Plant	**111,719**	89,944
Deferred Income Taxes	**6,735**	4,284
Deferred Credits (Note 9)	**29,230**	20,558
Minority Interests (Note 10)	**40,008**	40,008
Balance Due on Acquisition (Notes 11 and 13)	**7,500**	
Shareholders' Equity (Note 11)	**675,770**	480,449
	$1,602,740	$1,314,088

APPROVED BY THE BOARD:

E. W. King

E. W. King, Director

D. R. B. McArthur

D. R. B. McArthur, Director

Canadian Utilities Limited

Consolidated Statement of Changes in Financial Position

Year ended December 31, 1981 with comparative figures for 1980

	1981	1980
	(Thousands)	
Sources of Working Capital		
Provided by operations		
Net earnings	**$ 81,437**	$ 61,613
Add (deduct) items not affecting working capital		
Depreciation	**36,782**	29,485
Allowance for equity funds used during construction	**(14,620)**	(12,366)
Other	**5,864**	5,012
	109,463	83,744
Increase in notes payable	**30,000**	33,000
Issue of long-term debt	**73,546**	100,000
Issue of shares	**173,961**	50,000
Contributions for extensions to plant	**24,853**	19,060
Disposition of property, plant and equipment	**1,230**	496
Other	**14,660**	8,586
	427,713	294,886
Uses of Working Capital		
Purchase of property, plant and equipment	**235,145**	266,984
Less allowance for equity funds used during construction	**13,512**	11,689
	221,633	255,295
Acquisition of petroleum and natural gas subsidiary less working capital assumed	**48,772**	
Reduction in notes payable	**60,000**	
Reduction in long-term debt	**13,815**	8,614
Dividends	**46,989**	35,723
Preferred shares purchased for cancellation	**5,088**	2,057
Increase in deferred expenses	**13,004**	9,885
	409,301	311,574
Increase (Decrease) in Working Capital	**$ 18,412**	$(16,688)

Summary of Significant Accounting Policies

December 31, 1981

Basis of consolidation and accounting

The consolidated financial statements include the accounts of the Company, the major operating subsidiaries (Alberta Power Limited, Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited) and all other subsidiaries. Since the major operating subsidiaries are regulated utilities, their accounting records and policies reflect decisions made by regulatory bodies, principally the Public Utilities Board of Alberta, as part of the rate making process. Revenues are recognized on the basis of cycle billing and are recorded when customers are billed.

Property, plant and equipment

The utility subsidiaries include an allowance for funds used during construction, at a rate approved by the Public Utilities Board for debt and equity funds, in the cost of additions. Also, on retirement of depreciable assets, the accumulated depreciation is charged with the cost of the retired unit less net salvage. Gains and losses on extraordinary retirements are recognized in earnings as extraordinary items.

Certain additions are made with assistance of cash contributions where the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as and offset the depreciation charge of the assets to which they relate.

For the non-regulated petroleum and natural gas properties the Company follows the full cost method of accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in a single cost centre.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. The major assets are depreciated using rates approved by the Public Utilities Board varying from 2.1% to 6.6%. All resource properties are depreciated on a unit of production basis.

Leases

The Public Utilities Board requires that application be made for the capitalization of leases in the determination of customer rates. Prior to such approval, leases that would otherwise be treated as capital leases are accounted for as operating leases.

Deferred expenses

The regulated subsidiaries include in gas exploration those expenditures, net of income taxes, related to the development of gas reserves. Costs related to a successful venture are capitalized as plant and equipment. The costs of an unsuccessful venture are charged against deferred credits.

Expenses of issue of long-term debt are amortized over the weighted average life of the debt and expenses of issue of preferred shares are amortized over the lesser of the expected life of the issue or 30 years.

Other deferred expenses are amortized over varying periods not exceeding 40 years.

Deferred credits

As Alberta gas producers, the gas subsidiaries receive a pro rata share of monies available under The Natural Gas Price Administration Act. The monies, net of royalties and income taxes, are deferred and, subject to Public Utilities Board approval, are reduced by the costs of unsuccessful gas exploration.

Income taxes

The utility subsidiaries, except as noted below, do not follow deferred tax accounting and record in their accounts only income taxes currently payable. Deductions claimed in calculating the amount of current taxes exceed costs charged in the accounts, thereby reducing income taxes otherwise payable.

Since the income tax component of rates is designed only to recover income taxes currently payable, the customer in future years will bear an additional charge when recorded expenses exceed deductions for income tax purposes.

Effective October 1, 1981 Alberta Power Limited received approval from the Public Utilities Board to provide for current taxes by claiming as deductions for tax purposes only amounts recorded in the accounts. This method is referred to as the "Normalization — All Taxes Paid" method. For this company, therefore, there will be no further increase in the amount of unrecorded deferred taxes which arose in past years and which could become a future charge.

The utility subsidiaries are permitted to record deferred income taxes with respect to acquisition of natural gas rights, deferred gas costs and share issue costs.

Natural gas supply

The Province of Alberta enacted The Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas customers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the gas subsidiaries are reimbursed for the portion of the price paid to their suppliers which exceeds the support price.

Notes to Consolidated Financial Statements

December 31, 1981

1. Natural gas supply expense

The natural gas supply expense is net of an Alberta Government rebate of $79,112,000 (1980 — $117,760,000).

2. Taxes — other than income

	Year ended December 31	
	1981	1980
	(Thousands)	
Federal excise taxes	**$119,096**	$19,786
Petroleum and natural gas revenue taxes	**3,388**	
Canadian ownership taxes	**26,868**	
Franchise taxes	**37,440**	26,853
Property taxes	**8,118**	5,965
Provincial mineral taxes	**924**	556
	$195,834	$53,160

3. Income taxes

Income tax expense includes deferred taxes of $1,605,000 (1980 — $5,771,000).

Recorded income tax expense differs from the amount that would be expected if current income tax rates were applied to income before income taxes as follows:

	Year ended December 31			
	1981		1980	
	(Thousands)	**% of Pre-tax Earnings**	(Thousands)	% of Pre-Tax Earnings
Earnings before income taxes	**$114,988**		$85,752	
Expected income tax expense	**$ 56,114**	**48.8**	$41,847	48.8
Capital cost allowance in excess of depreciation	**(9,374)**	**(8.3)**	(6,805)	(7.9)
Allowance for funds used during construction	**(11,994)**	**(10.4)**	(9,591)	(11.2)
Crown royalties and other non-deductible Crown payments	**7,656**	**6.7**	5,690	6.6
Earned depletion and resource allowance	**(6,809)**	**(5.9)**	(6,271)	(7.3)
Other	**(4,968)**	**(4.3)**	(3,286)	(3.8)
	$ 30,625	**26.6**	$21,584	25.2

As described in the Summary of Significant Accounting Policies, a provision for certain deferred taxes is not included in the consolidated financial statements. Unbooked deferred taxes increased during the year by $16,385,000 (1980 — $18,832,000) to an accumulated amount of $116,581,000.

4. Accounts receivable

	December 31	
	1981	1980
	(Thousands)	
Customer accounts	**$ 93,337**	$106,470
Receivable from the Province of Alberta	**43,798**	33,921
Other receivables and deposits	**38,405**	30,951
	$175,540	$171,342

5. Property, plant and equipment

	December 31			
	1981		1980	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Natural gas utility plant and equipment	**$ 610,192**	**$142,919**	$ 535,653	$129,736
Electric utility plant and equipment	**814,571**	**127,290**	491,229	106,741
Construction work in progress	**79,189**		252,012	
Non-regulated petroleum and natural gas properties	**53,894**	**1,034**	4,098	539
Other plant and equipment	**29,172**	**4,840**	29,024	3,392
Undertakings, franchise and gas rights			8,000	
Land	**7,588**		4,073	
	$1,594,606	**$276,083**	$1,324,089	$240,408
Net property, plant and equipment	**$1,318,523**		$1,083,681	

6. Deferred expenses

	December 31	
	1981	1980
	(Thousands)	
Gas exploration — net	**$26,798**	$16,439
Unamortized debt and preferred share issue expenses	**13,298**	9,845
Other	**1,933**	3,549
	$42,029	$29,833

7. Notes payable

Under a bank loan agreement, which provides a line of credit of up to $150,000,000 to March 14, 1983, the Company issues commercial paper and assumes bank loans. Under the agreement the Company maintains an unused bank line of credit of not less than 50% of the commercial paper outstanding. At December 31, 1981 there were no bank loans outstanding (1980 — $60,000,000).

On April 1, 1981 the Company arranged a private sale of a $30,000,000 floating rate note, due September 30, 1982, with an interest rate equal to a bank prime rate less 3/8 of 1% and which is renewable by the lender at 15-month intervals to June 30, 1991.

8. Long-term debt

Long-term debt outstanding, net of current maturities, is as follows:

	December 31	
	1981	1980
	(Thousands)	
Canadian Utilities Limited		
Sinking fund debentures 8 3/8% to 17% due to 2002	**$352,487**	$310,088
Capitalized lease obligation	**22,570**	
Alberta Power Limited		
First mortgage sinking fund bonds 4 1/8% to 6 1/2% due to 1992	**25,000**	25,000
Sinking fund debentures 7 1/4% to 9 5/8% due to 1991	**18,548**	19,394
Northwestern Utilities Limited		
First mortgage sinking fund bonds 5 3/8% to 9 3/4% due to 1994	**17,072**	17,807
Sinking fund debentures 7 1/4% due 1985	**2,282**	2,388
Canadian Western Natural Gas Company Limited		
First mortgage sinking fund bonds 5 3/8% to 7% due to 1992	**9,133**	12,309
Sinking fund debentures 9 3/4% due 1990	**6,250**	6,625
Total long-term debt	**$453,342**	$393,611

Annual sinking fund requirements, capitalized lease requirement and repayment of maturing issues for each of the following years are:

	Maturing Issues	Capitalized Lease Requirements	Sinking Fund Requirements	Sinking Fund Purchased in Advance	Total
			(Thousands)		
1982	$2,785	$663	$11,798	$(8,279)	$ 6,967
1983	4,650	714	12,048	(252)	17,160
1984		770	12,698	(42)	13,426
1985	2,070	830	16,417		19,317
1986	5,000	894	21,417		27,311

The Company leases, with an option to purchase, a dragline costing $24,836,000 which is included in the property account under electric utility plant and equipment. The future minimum payments are $2,421,000 per year for the next five years and $29,540,000 in later years. The imputed interest included in these future minimum rentals at the rate of 7.62% implicit in the lease is $18,412,000.

9. Deferred credits

	December 31 1981	December 31 1980
	(Thousands)	
Funds received under the Natural Gas Price Administration Act — net	**$24,368**	$16,554
Other	**4,862**	4,004
	$29,230	$20,558

During the year $1,066,000 (1980 — Nil) of unsuccessful gas exploration costs were charged against monies received under the Natural Gas Price Administration Act.

10. Minority interests

	December 31 1981	December 31 1980
	(Thousands)	
Minority interest in the preferred shares of subsidiaries:		
Northwestern Utilities Limited		
105,000 4% Cumulative Redeemable Preference Shares; voting, non-participating	**$10,500**	$10,500
Canadian Western Natural Gas Company Limited		
275,410 4% Cumulative Redeemable Preference Shares; voting, non-participating	**5,508**	5,508
200,000 5½% Cumulative Redeemable Preference Shares; voting, non-participating	**4,000**	4,000
CU Ethane Limited		
800,000 Floating Rate Cumulative Redeemable Preferred Shares; guaranteed by the parent company and with a dividend rate of one-half of bank prime rate plus 1¼% and with a redemption of $2,000,000 per year commencing in 1989	**20,000**	20,000
	$40,008	$40,008

11. Shareholders' equity

Authorized Share Capital:

Preferred Shares

40,000 5% Cumulative Redeemable Preferred Shares.

150,000 Series Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Preferred Shares and rank pari passu with the 5% Cumulative Redeemable Preferred Shares.

An unlimited number of Series Second Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Second Preferred Shares.

Common Shares

An unlimited number of shares without nominal or par value.

Issued Share Capital and Retained Earnings:

	December 31			
	1981		1980	
	Number	**Amount (Thousands)**	Number	Amount (Thousands)
Cumulative redeemable preferred shares 5%	**40,000**	**$ 4,000**	40,000	$ 4,000
Cumulative redeemable preferred shares				
4¼% Series	**15,000**	**1,500**	15,000	1,500
6% Series	**50,000**	**5,000**	50,000	5,000
Cumulative redeemable second preferred shares				
10¼% Series A	**1,106,400**	**27,660**	1,152,000	28,800
9.24% Series B	**1,504,000**	**37,600**	1,552,000	38,800
7.30% Series C	**1,088,980**	**27,224**	1,124,980	28,125
10.24% Series D	**1,960,000**	**49,000**	2,000,000	50,000
10.12% Series E	**2,166,100**	**54,153**		
14.00% Series F	**3,000,000**	**75,000**		
Common shares	**22,968,026**	**243,236**	20,817,623	199,275
Retained earnings		**151,397**		124,949
		$675,770		$480,449

Stated Values, Redemption Premiums and Dividends:

	Stated Value	Maximum Redemption Premium	Dividends Year ended December 31 **1981**	1980
			(Thousands)	
Cumulative redeemable preferred shares 5%	$100	4%	**$ 200**	$ 200
Cumulative redeemable preferred shares				
4¼% Series	$100	2½%	**64**	64
6% Series	$100	3%	**300**	300
Cumulative redeemable second preferred shares				
10¼% Series A	$ 25	5%	**2,897**	2,952
9.24% Series B	$ 25	5%	**3,523**	3,658
7.30% Series C	$ 25	4%	**2,018**	2,083
10.24% Series D	$ 25	4%	**5,085**	2,630
10.12% Series E	$ 25	4%	**4,301**	
14.00% Series F	$ 25	4%	**2,475**	
Common shares			**26,126**	23,836
			$46,989	$35,723

During 1981 the Company issued $55,000,000 Series E Cumulative Redeemable Second Preferred Shares, $75,000,000 Series F Cumulative Redeemable Second Preferred Shares, 150,403 Common Shares for cash under the employee share purchase plan and 2,000,000 Common Shares for consideration as described in Note 13 to the consolidated financial statements.

The bond and debenture indentures place limitations on the Company and its subsidiaries, including restrictions on the payment of dividends. Consolidated retained earnings in the amount of $106,215,000 were free from such restrictions.

Redemption

The Cumulative Redeemable Preferred Shares, and the Cumulative Redeemable Second Preferred Shares may be redeemed at the option of the Company after specified dates subject to premiums listed plus accrued dividends.

Purchase obligations

The Company is required in each year to make all reasonable efforts to purchase for cancellation the number of shares of the Cumulative Redeemable Second Preferred Shares listed below at a price not exceeding $25 per share plus costs of purchase. If after all reasonable efforts the Company is unable to do so, the Company's obligation to purchase shares in such year is extinguished.

		Current Purchase Obligation	Purchased in 1981 Number	Amount
				(Thousands)
10¼%	Series A	48,000	45,600	$1,140
9.24%	Series B	48,000	48,000	1,200
7.30%	Series C	36,000	36,000	900
10.24%	Series D	40,000	40,000	1,000
10.12%	Series E	44,000	33,900	848
14.00%	Series F	120,000		
				$5,088

Retraction privileges

Certain series of the Cumulative Redeemable Second Preferred Shares have retraction privileges on specified dates at the option of the holder at the stated value plus accrued dividends. The series and retraction dates are shown below:

Series D June 1, 1985 and June 1, 1990
Series E March 1, 1988
Series F October 1, 1984 and October 1, 1989

Reserved shares

The Company has reserved 247,279 unissued Common Shares for issuance under the employee share purchase plan. The rights to purchase are exercisable for $18.81 per share on December 31, 1983.

The Company is committed to issue an estimated 360,000 Common Shares upon finalization of the transaction described in Note 13 to the consolidated financial statements.

12. Commitments

The cost of the planned construction and expansion program for 1982 is estimated to be $325,000,000. As at December 31, 1981 commitments under contract totaled approximately $211,000,000 for 1982 and future years.

Minimum yearly non-capitalized lease payments are $9,045,000, $10,448,000, $9,794,000, $9,539,000, $10,082,000 for the years 1982-1986 respectively. Leases range in length from three to ten years.

The pension plan has an unfunded past service liability amounting to approximately $7,100,000. This amount will be funded over a period not exceeding 12 years.

13. Acquisition

The Company entered into an agreement dated December 15, 1981 with three subsidiaries of ATCO Ltd., a principal shareholder of the Company, by which the Company acquired, through the issuance of Treasury Shares, all of the issued and outstanding shares of 281159 Alberta Ltd. which owns petroleum and natural gas properties. On December 15, 1981 the Company, based on an initial evaluation of the petroleum and natural gas properties, issued as partial consideration a total of 2,000,000 Common Shares valued at $41,500,000. In accordance with the agreement additional Common Shares will be issued upon receipt of further evaluations.

Subsequently, when all final adjustments are known and the final purchase price is determined, additional Common Shares, if required, will be issued to bring the total value of the Common Shares issued up to the final purchase price. In the event the value of the Common Shares previously issued exceeds the final purchase price, the difference will be paid by the three subsidiaries of ATCO Ltd. to the Company in cash.

The acquisition has been accounted for as a purchase and the results of operations from December 15, 1981 have been included in the consolidated financial statements. As at December 31, 1981 $49,000,000 was the estimate of the total consideration required and accordingly $7,500,000, representing an estimate of the balance to be settled by the issuance of additional Common Shares, has been recorded in the consolidated financial statements.

14. Amounts held in trust

Trust accounts are maintained for funds contributed by members of Rural Electrification Associations. These funds, amounting to $14,608,000 (1980 — $13,379,000), have been invested in securities approved by the Alberta Director of Co-operative Activities.

Income taxes rebatable to customers amounting to $4,621,000 (1980 — $4,559,000) under the Utility Companies Income Tax Rebates Act, 1977 are also held in trust.

Amounts held in trust are not shown in the consolidated financial statements.

15. Segmented Information

Financial information relating to segments of the Company's business is presented below:

Operating Segments	Electric		Natural Gas		Other		Consolidated*	
(Thousands)	**1981**	1980	**1981**	1980	**1981**	1980	**1981**	1980
Revenues								
Outside customers	**$201,678**	$149,847	**$779,169**	$581,677	**$43,352**	$26,172	**$1,024,564**	$ 757,696
Inter-segment	**569**	411	**17,753**	16,394	**3,203**	109		
	202,247	150,258	**796,922**	598,071	**46,555**	26,281	**1,024,564**	757,696
Operating expenses								
Operating	**101,432**	79,985	**731,923**	542,536	**38,341**	19,669	**850,463**	625,276
Depreciation	**20,946**	15,958	**13,929**	11,904	**2,170**	1,623	**36,782**	29,485
	122,378	95,943	**745,852**	554,440	**40,511**	21,292	**887,245**	654,761
Segment operating income	**79,869**	54,315	**51,070**	43,631	**6,044**	4,989	**137,319**	102,935
Income deductions	**12,296**	3,899	**14,282**	15,412	**(1,321)**	427	**25,257**	19,738
Income taxes	**17,817**	11,810	**9,255**	7,623	**3,672**	2,151	**30,625**	21,584
Net earnings	**$ 49,756**	$ 38,606	**$ 27,533**	$ 20,596	**$ 3,693**	$ 2,411	**$ 81,437**	$ 61,613
Total assets	**$814,211**	$674,917	**$683,613**	$602,614	**$110,829**	$43,349	**$1,602,740**	$1,314,088
Capital expenditures	**$153,484**	$190,148	**$ 80,931**	$ 75,546	**$ 730**	$ 1,290	**$ 235,145**	$ 266,984

* Inter-segment transactions have been eliminated in the consolidated column.

16. Financial statements

The 1980 figures are based upon consolidated financial statements which were reported upon by other auditors. Certain of the 1980 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1981.

17. Subsequent event

The Company entered into an agreement dated January 25, 1982 with its underwriters for the sale to them on February 10, 1982 of 2,000,000 Cumulative Redeemable Second Preferred Shares Series G at a price of $25 per share, amounting to $50,000,000. The net proceeds to be received are estimated to be $48,300,000 after deducting underwriters' fees and other expenses of issue.

Canadian Utilities Limited

Consolidated Ten-Year Financial Summary

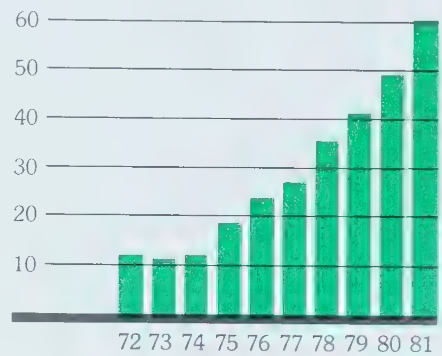
(Dollars in millions, except as indicated)

	1981	1980	1979	1978
Operating Revenues				
Natural gas	**779.2**	581.7	477.9	431.8
Electric	**201.7**	149.8	124.6	114.7
Other	**43.7**	26.2	23.2	7.7
	1,024.6	757.7	625.7	554.2
Operating Expenses				
Natural gas supply	**442.2**	405.8	342.3	315.5
Operating and maintenance	**212.5**	166.3	139.1	107.2
Taxes — other than income	**195.8**	53.2	28.0	26.6
Depreciation	**36.8**	29.5	26.5	23.2
	887.3	654.8	535.9	472.5
	137.3	102.9	89.8	81.7
Allowance for Funds Used During Construction	**24.6**	19.7	7.1	4.7
Other Income	**6.8**	2.7	1.5	2.5
	168.7	125.3	98.4	88.9
Interest Expense	**53.7**	39.5	27.4	22.4
	115.0	85.8	71.0	66.5
Income Taxes	**30.6**	21.6	17.5	20.0
	84.4	64.2	53.5	46.5
Minority Interests	**2.9**	2.6	2.3	1.5
Net Earnings before Extraordinary Items	**81.5**	61.6	51.2	45.0
Extraordinary Items — Non-Recurring Gain (Loss)				
Net Earnings	**81.5**	61.6	51.2	45.0
Preferred Dividend Requirements	**21.4**	12.3	9.4	9.4
Balance Attributable to Common Shares	**60.1**	49.3	41.8	35.6
Contribution by Operating Segment*				
Before Extraordinary Items				
Electric	**34.5**	29.3	21.7	18.7
Natural gas	**21.4**	17.6	18.1	15.7
Other	**4.2**	2.4	2.0	1.2
	60.1	49.3	41.8	35.6
Common Shares Outstanding (thousands)				
End of year	**22,968**	20,818	20,818	18,626
Average for year	**20,963**	20,992	18,783	18,146
Earnings — Dollars Per Common Share				
Net earnings before extraordinary items	**2.87**	2.37	2.23	1.97
Net earnings after extraordinary items	**2.87**	2.37	2.23	1.97
Common Dividends Paid*				
Dividends per share (dollars)	**1.255**	1.145	1.015	.9125
Total dividends paid	**26.1**	23.8	18.9	16.4
Payout Ratio*				
Dividends paid ÷ earnings available	**43.5%**	48.3%	45.2%	45.9%
Common Shareholders' Equity Dollars Per Share*				
At year end	**17.18**	15.21	14.00	12.22
Rate of Return on Common Shareholders' Equity*				
Before extraordinary items	**16.7%**	15.6%	15.9%	16.1%
After extraordinary items	**16.7%**	15.6%	15.9%	16.1%
Stock Market Record of Common Shares* (dollars)				
High	**25**	27	21	18
Low	**19½**	18¼	16	14⅛
Close	**21¾**	22¾	19	16⅛
Gross Fixed Assets	**1,594.6**	1,324.1	1,059.3	883.9
Net Fixed Assets	**1,318.5**	1,083.7	849.4	700.1
Total Assets	**1,602.7**	1,314.1	1,000.6	832.9
Capitalization*				
Long-term debt	**453.3**	393.6	302.2	233.7
Contributions	**111.7**	89.9	73.3	59.5
Preferred shares	**321.2**	196.2	148.3	149.2
Common equity	**394.6**	316.2	290.3	226.9
Total capitalization	**1,280.8**	995.9	814.1	669.3
Capitalization Ratio*				
Long-term debt	**42%**	39%	37%	35%
Contributions	**10%**	9%	9%	9%
Preferred shares	**26%**	20%	18%	22%
Common equity	**22%**	32%	36%	34%
Times Debt Interest Earned (pretax)*	**3.14**	3.17	3.60	3.97

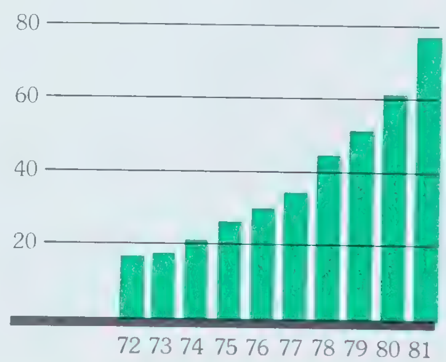
* Not applicable prior to 1972 corporate reorganization.
Note: Comparative figures for years prior to 1972 have been reclassified to conform with financial presentation following corporate reorganization in 1972.

1977	1976	1975	1974	1973	1972	1971
318.7	216.5	141.8	91.2	82.0	78.9	70.3
93.9	78.1	57.9	46.3	38.3	33.8	30.6
2.8	1.3	.7	.3	.1		
415.4	295.9	200.4	137.8	120.4	112.7	100.9
221.3	134.8	70.9	40.2	36.0	32.4	27.0
87.2	72.8	56.5	43.6	34.7	33.4	29.1
21.8	17.0	11.8	8.0	6.8	6.5	6.0
18.8	15.6	13.3	12.9	11.0	10.1	9.7
349.1	240.2	152.5	104.7	88.5	82.4	71.8
66.3	55.7	47.9	33.1	31.9	30.3	29.1
2.3	1.3	4.0	1.6	.8	2.2	.8
1.4	2.3	1.4	1.0	.8	.8	1.3
70.0	59.3	53.3	35.7	33.5	33.3	31.2
21.4	22.3	19.9	17.2	13.7	12.2	9.9
48.6	37.0	33.4	18.5	19.8	21.1	21.3
12.5	8.6	8.7	2.4	4.5	5.0	7.2
36.1	28.4	24.7	16.1	15.3	16.1	14.1
.9	.9	.9	.9	.9	1.0	1.2
35.2	27.5	23.8	15.2	14.4	15.1	12.9
(1.6)		2.4	.5		(.1)	.2
33.6	27.5	26.2	15.7	14.4	15.0	13.1
7.5	3.8	5.1	2.8	2.8	2.7	2.5
26.1	23.7	21.1	12.9	11.6	12.3	10.6
15.4	12.8	10.7	7.2	6.8	9.1	
11.7	10.8	7.9	5.2	4.8	3.3	
.6	.1	.1				
27.7	23.7	18.7	12.4	11.6	12.4	
17,122	16,634	14,198	10,075	10,065	10,063	10,056
17,312	15,567	14,258	14,216	14,216	14,216	9,503
1.61	1.55	1.45	1.05	.99	1.05	.91
1.52	1.55	1.61	1.08	.99	1.04	.93
.8525	.765	.65	.59	.55	.52	
14.4	11.0	7.1	5.9	5.5	5.2	
55.2%	46.4%	33.6%	45.7%	47.4%	42.3%	
11.06	10.36	9.41	8.49	8.04	7.61	
14.6%	14.9%	15.4%	12.4%	12.3%	13.8%	
13.7%	14.9%	17.1%	12.7%	12.3%	13.7%	
15½	14⅜	9⅞	11	13¾	14⅝	
12⅝	9½	7⅝	6½	8⅝	9¼	
15½	14⅜	9¾	7¼	9¼	13½	
780.5	688.6	613.6	538.7	470.3	435.8	397.2
618.8	542.3	478.6	413.5	355.8	330.2	300.0
731.5	632.0	564.1	466.8	385.0	357.2	322.8
244.3	225.7	181.1	194.5	167.5	156.0	
47.5	37.8	27.6	18.1	14.4	12.7	
129.3	99.3	55.3	30.5	30.5	30.5	
187.5	173.9	138.6	115.3	108.9	102.8	
608.6	536.7	402.6	358.4	321.3	302.0	
40%	42%	45%	54%	52%	52%	
8%	7%	7%	5%	5%	4%	
21%	19%	14%	9%	9%	10%	
31%	32%	34%	32%	34%	34%	
3.26	2.66	2.68	2.08	2.45	2.32	

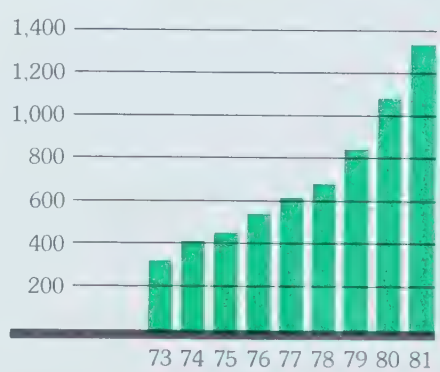
Net Earnings Attributable to Common Shares
(excluding extraordinary items)
(millions of dollars)



Cash Flow Reinvested
(millions of dollars)
(cash flow from operations less dividends paid)



Net Assets
(millions of dollars)
Total assets less current liabilities



Canadian Utilities Limited

Ten-Year Operating Summary

(Dollars in millions, except as indicated)

	1981	1980	1979	1978
Electric Operations				
Construction work in progress	**68.9**	243.8	107.7	31.5
Fixed assets in service	**817.8**	493.2	439.8	407.2
Gross fixed assets at cost	**886.7**	737.0	547.5	438.7
Accumulated depreciation	**127.3**	106.7	89.9	75.4
Net fixed assets	**759.4**	630.3	457.6	363.3
% growth over prior year	**21%**	38%	26%	10%
Capital additions in the year	**153.0**	190.1	110.7	48.1
Sales (millions of kilowatt hours) — retail	**3,190**	2,994	2,779	2,512
% growth over prior years	**7%**	8%	11%	7%
Average annual use per residential customer (kWh)	**6,988**	7,073	7,162	7,058
Average annual billing per residential customer ($)	**474**	405	366	358
Maximum hourly demand (thousands of kilowatts)	**652**	607	573	520
Generating capacity (thousands of kilowatts)	**1,054**	670	668	668
Customers at year-end (thousands)	**134.6**	128.8	120.1	112.5
Number of communities served	**399**	395	392	387
Power lines (thousands of kilometres)	**25.3**	23.7	23.0	22.3
Gas Operations				
Gross fixed assets at cost	**624.7**	553.9	479.8	416.8
Accumulated depreciation	**142.9**	129.7	117.7	107.6
Net fixed assets	**481.8**	424.2	362.1	309.2
% growth over prior year	**14%**	17%	17%	14%
Capital additions in the year	**80.1**	75.6	64.5	48.2
Sales (petajoules)	**372**	392	392	357
% growth over prior year	**7%**	Nil	9%	18%
Average annual use per residential customer (gigajoules)	**165**	190	207	201
Average annual billing per residential customer ($)	**434**	336	308	299
Maximum daily demand (terajoules)	**2,048**	2,051	2,003	1,978
Degree days — Edmonton	**4,595**	5,396	5,636	5,530
Calgary	**4,365**	5,082	5,366	5,592
Customers at year-end (thousands)	**549.8**	520.0	489.8	457.4
Number of communities served	**272**	269	272	265
Pipelines (thousands of kilometres)	**29.3**	27.9	27.1	25.0
Other operations				
Gross fixed assets at cost	**83.2**	33.3	32.0	28.4
Accumulated depreciation	**5.9**	3.9	2.3	.8
Net fixed assets	**77.3**	29.4	29.7	27.6
Total Number of Employees	**4,313**	4,144	3,870	3,592

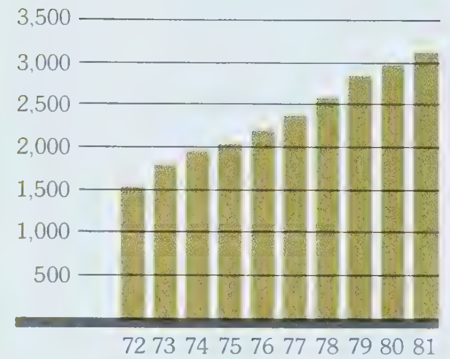
1977	1976	1975	1974	1973	1972	1971
34.4	20.0	14.3	42.9	11.7	38.9	26.9
358.6	332.7	295.0	217.8	206.5	159.3	148.6
393.0	352.7	309.3	260.7	218.2	198.2	175.5
62.2	53.2	45.7	41.2	36.0	31.8	28.3
330.8	299.5	263.6	219.5	182.2	166.4	147.2
10%	14%	20%	20%	9%	13%	20%
44.1	45.9	51.1	44.8	21.3	24.5	29.1
2,358	2,182	2,025	1,920	1,783	1,520	1,275
8%	8%	5%	8%	17%	19%	14%
6,764	6,773	6,673	6,251	5,954	5,704	5,451
310	281	223	187	169	162	158
524	455	445	388	376	342	295
671	686	686	523	512	370	367
106.9	99.6	94.0	88.8	84.6	80.5	77.2
385	368	365	364	365	365	359
20.8	20.1	19.3	18.8	18.1	17.4	16.0

370.9	333.9	300.8	275.5	251.7	236.9	221.2
99.3	93.0	89.3	83.9	78.6	73.8	68.9
271.6	240.9	211.5	191.6	173.1	163.1	152.3
13%	14%	10%	11%	6%	7%	3%
38.8	39.4	29.5	25.7	17.1	16.5	10.6
304	273	264	251	249	241	215
12%	3%	5%	1%	3%	13%	10%
190	195	224	219	224	243	230
241	190	156	115	113	120	114
1,681	1,508	1,390	1,295	1,170	1,194	1,176
5,124	4,891	5,555	5,492	5,538	6,028	5,737
5,289	4,885	5,750	5,230	5,428	5,973	5,532
428.4	400.5	373.3	353.3	335.5	317.8	303.3
260	257	253	253	253	251	249
23.1	21.8	19.5	16.7	15.8	15.2	14.8

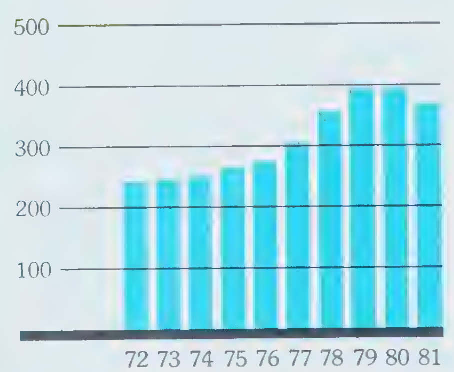
16.6	2.0	1.0	1.0			
.3	.2	.1				
16.3	1.8	.9	1.0			

3,367	3,161	3,133	2,933	2,746	2,576	2,298

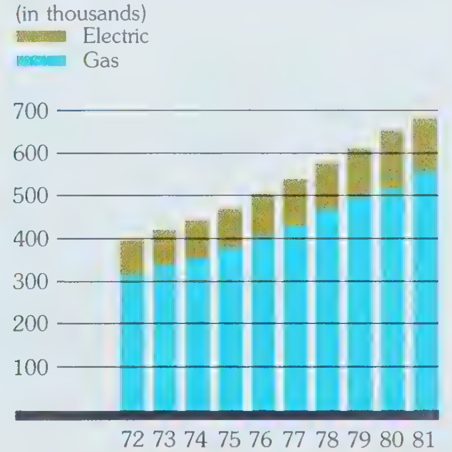
Electric Sales
(millions of kilowatt hours)



Natural Gas Sales
(petajoules)



Gas and Electric Customers at Year-end
(in thousands)



Board of Directors


W. L. Britton


G. L. Crawford, Q.C.


B. K. French


W. D. Grace


V. L. Horte


E. W. King


R. W. A. Laidlaw


P. L. P. Macdonnell, Q.C.


D. R. B. McArthur


W. S. McGregor


C. S. Richardson


D. M. Ritchie


N. W. Robertson


R. D. Southern


J. D. Wood

Corporate Information

Canadian Utilities Limited

(Incorporated under the laws of Canada)

Board of Directors

W. L. Britton°†
Barrister and Solicitor
Bennett Jones
Calgary, Alberta

G. L. Crawford, Q.C.°†
Barrister and Solicitor
McLaws & Company
Calgary, Alberta

B. K. French*
Secretary Treasurer
Nimo Holdings Ltd.
Calgary, Alberta

W. D. Grace
Senior Vice-President, Finance
Canadian Utilities Limited
Edmonton, Alberta

V. L. Horte°
President
V. L. Horte Associates Limited
Calgary, Alberta

E. W. King°†
President and Chief Executive Officer
Canadian Utilities Limited
Edmonton, Alberta

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President
Gibson Petroleum Company Limited
Calgary, Alberta

P. L. P. Macdonnell, Q.C.†
Barrister and Solicitor
Milner & Steer
Edmonton, Alberta

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Corporate Director
Edmonton, Alberta

W. S. McGregor*
President
Numac Oil & Gas Ltd.
Edmonton, Alberta

C. S. Richardson°
Senior Vice-President, Finance
ATCO Ltd.
Calgary, Alberta

D. M. Ritchie
President
Medway Investments Corporation Limited
Edmonton, Alberta

N. W. Robertson°*
Executive Vice-President and Chief Operating Officer
ATCO Ltd.
Calgary, Alberta

R. D. Southern°
President and Chief Executive Officer
ATCO Ltd.
Calgary, Alberta

J. D. Wood
President and Chief Executive Officer
ATCO Industries (N.A.) Ltd.
Calgary, Alberta

°member of Executive Committee
*member of Audit Committee
†member of Human Resources Committee

Officers and Staff Executives

R. D. Southern
Chairman of the Board

C. S. Richardson
Deputy Chairman of the Board

E. W. King
President and Chief Executive Officer

W. D. Grace
Senior Vice-President, Finance

H. N. Bottomley
Vice-President and Controller

D. R. Brandt
Vice-President

A. E. Scott
Vice-President

A. M. Anderson
Secretary

C. K. Sheard
General Counsel and Assistant Secretary

J. A. Walker
Treasurer

Corporate Information

Subsidiary Company Executives

ALBERTA POWER LIMITED

R. D. Southern
Chairman of the Board

J. D. Wood
Deputy Chairman of the Board

E. W. King
President and Chief Executive Officer

Keith Provost
Senior Vice-President

R. H. Choate
Vice-President, Administration

J. R. Frey
Vice-President, Planning

D. B. Mitchell
Vice-President, Industrial Relations

J. E. A. Morin
Vice-President, Engineering and Construction

G. N. Paicu
Vice-President, Energy Supply

C. O. Twa
Vice-President, Customer Services

A. J. Pullman
Controller

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
and
NORTHWESTERN UTILITIES LIMITED

R. D. Southern
Chairman of the Board

J. D. Wood
Deputy Chairman of the Board

E. W. King
President and Chief Executive Officer

B. M. Dafoe
Senior Vice-President

A. J. L. Fisher
Vice-President and General Manager
Canadian Western Natural Gas Company Limited

R. G. Lock
Vice-President and General Manager
Northwestern Utilities Limited

W. L. Graburn
Vice-President, Gas Supply

D. B. Mitchell
Vice-President, Industrial Relations

H. R. Lewis
Controller, Northwestern Utilities Limited

T. J. Storey
Controller, Canadian Western Natural Gas Company Limited

CU ENGINEERING LIMITED

D. M. Murray
Vice-President and General Manager

CU ETHANE LIMITED

E. W. King
President and Chief Executive Officer

CU RESOURCES LIMITED

D. L. Weiss
Vice-President

Canadian Utilities Limited

Registered Head Office

10040 - 104th Street
Edmonton, Alberta, Canada
T5J 2V6
Telephone: (403) 420-7310

Transfer Agent and Registrar

Common Shares and Preferred Shares:
Montreal Trust Company
Halifax/Montreal/Toronto/Winnipeg
Regina/Calgary/Edmonton/Vancouver

Trustee and Registrar

Debentures:
National Trust Company
Montreal/Toronto/Winnipeg
Calgary/Edmonton/Vancouver

Stock Exchange Listings

Common Shares:
Toronto, Montreal and Alberta Stock Exchanges

Preferred and Series Preferred Shares:
Toronto Stock Exchange

Second Preferred Shares:
Toronto and Montreal Stock Exchanges

Auditors

Price Waterhouse
2401 Toronto Dominion Tower
Edmonton Centre
Edmonton, Alberta

Valuation Day

The Valuation Day price of Canadian Utilities' common shares adjusted for the stock split of September 15, 1972 was $9.31.

Annual Meeting

The annual meeting of shareholders will be held at 11:00 a.m., April 23, 1982 at the Hotel Macdonald, Edmonton, Alberta.

Canadian Utilities Limited will move its headquarters to this building under construction in Edmonton. The building will also house the administrative offices of Alberta Power Limited and Northwestern Utilities Limited. Developer of the property is ATCO Development Corporation.

CANADIAN UTILITIES LIMITED

An ATCO Company

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